NATIONAL FUEL GAS CO
Form 10-Q
May 01, 2009

Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended March 31, 2009
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from_____ to_____
Commission File Number 1-3880

NATIONAL FUEL GAS COMPANY
(Exact name of registrant as specified in its charter)

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

(716) 857-7000
(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. YES__X__ NO _____

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). YES_____ NO_____

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__X__

Accelerated filer _____ Non-accelerated filer _____ (Do not check if a smaller reporting company) Smaller Reporting Company _____

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES _____ NO__X__

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 April 30, 2009: 79,517,616 shares.

Table of Contents

GLOSSARY OF TERMS

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

National Fuel Gas Companies	
Company	The Registrant, the Registrant and its subsidiaries or the Registrant s subsidiaries as appropriate in the context of the disclosure
Data-Track	Data-Track Account Services, Inc.
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.
Leidy Hub	Leidy Hub, Inc.
Midstream	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
SECI	Seneca Energy Canada Inc.
Seneca	Seneca Resources Corporation
Seneca Energy	Seneca Energy II, LLC
Supply Corporation	National Fuel Gas Supply Corporation
Regulatory Agencies	
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	
2008 Form 10-K	The Company s Annual Report on Form 10-K for the year ended September 30, 2008, as amended
ARB 51	Accounting Research Bulletin No. 51, Consolidated Financial Statements
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.

Table of Contents

GLOSSARY OF TERMS (Cont.)

Exchange Act	Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets	Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploration costs	Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
FIN	FASB Interpretation Number
FIN 48	FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes - an interpretation of SFAS 109
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)
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 (Open Season) time period are evaluated as if they had been submitted simultaneously.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped reserves	Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.
Reserves	The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Restructuring	

	Generally referring to partial deregulation of the utility industry 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-settled stock appreciation right
SFAS	Statement of Financial Accounting Standards

-3-

GLOSSARY OF TERMS (Concl.)

SFAS 87	Statement of Financial Accounting Standards No. 87, Employers Accounting for Pensions
SFAS 88	Statement of Financial Accounting Standards No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits
SFAS 106	Statement of Financial Accounting Standards No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes
SFAS 123R	Statement of Financial Accounting Standards No. 123R, Share-Based Payment
SFAS 131	Statement of Financial Accounting Standards No. 131, Disclosures about Segments of an Enterprise and Related Information
SFAS 132R	Statement of Financial Accounting Standards No. 132R, Employers Disclosures about Pensions and Other Postretirement Benefits
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 141R	Statement of Financial Accounting Standards No. 141R, Business Combinations
SFAS 157	Statement of Financial Accounting Standards No. 157, Fair Value Measurements
SFAS 158	Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of SFAS 87, 88, 106, and 132R
SFAS 160	Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51
SFAS 161	Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133
Stock acquisitions	Investments in corporations.
Unbundled service	A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
VEBA	Voluntary Employees Beneficiary Association
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

INDEX

	Part I. Financial Information	Page
Item 1.	Financial Statements (Unaudited)	
	a. Consolidated Statements of Income and Earnings Reinvested in the Business Three and Six Months Ended March 31, 2009 and 2008	6 - 7
	b. Consolidated Balance Sheets March 31, 2009 and September 30, 2008	8 - 9
	c. Consolidated Statements of Cash Flows Six Months Ended March 31, 2009 and 2008	10
	d. Consolidated Statements of Comprehensive Income Three and Six Months Ended March 31, 2009 and 2008	11
	e. Notes to Consolidated Financial Statements	12 - 29
Item 2.	Management s Discussion and Analysis of Financial Condition and Results of Operations	30 - 52
Item 3.	Quantitative and Qualitative Disclosures About Market Risk	52
Item 4.	Controls and Procedures	52
	Part II. Other Information	
Item 1.	Legal Proceedings	52 - 53
Item 1 A.	Risk Factors	53 - 55
Item 2.	Unregistered Sales of Equity Securities and Use of Proceeds	55 - 56
Item 3.	Defaults Upon Senior Securities	
Item 4.	Submission of Matters to a Vote of Security Holders	56 - 57
Item 5.	Other Information	
Item 6.	Exhibits	57

Signatures	58
EX-10.1	
EX-12	
EX-31.1	
EX-31.2	
EX-32	
EX-99	

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, predict believes, seeks, will, may, and similar expressions.

Table of Contents

Part I. Financial Information
Item 1. Financial Statements

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

(Thousands of Dollars, Except Per Common Share Amounts)	Three Months Ended March 31, 2009	2008
INCOME		
Operating Revenues	$804,645	$885,853
Operating Expenses		
Purchased Gas	485,468	531,438
Operation and Maintenance	118,449	120,584
Property, Franchise and Other Taxes	20,372	21,398
Depreciation, Depletion and Amortization	41,714	42,412
	666,003	715,832
Operating Income	138,642	170,021
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	974	1,030
Interest Income	1,005	2,177
Other Income	468	2,080
Interest Expense on Long-Term Debt	(17,545)	(16,289)
Other Interest Expense	(2,849)	(2,285)
Income Before Income Taxes	120,695	156,734
Income Tax Expense	47,211	61,730
Net Income Available for Common Stock	73,484	95,004
EARNINGS REINVESTED IN THE BUSINESS		
Balance at December 31	884,476	1,027,951
	957,960	1,122,955
Share Repurchases	-	(89,564)
Dividends on Common Stock (2009 - $0.325 per share; 2008 - $0.31 per share)	(25,841)	(25,307)
Balance at March 31	$932,119	$1,008,084
Earnings Per Common Share:		

Basic:		
Net Income Available for Common Stock	$0.92	$1.14
Diluted:		
Net Income Available for Common Stock	$0.92	$1.11
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	79,514,793	83,406,242
Used in Diluted Calculation	80,129,743	85,385,944

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

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

	Six Months Ended March 31,	
(Thousands of Dollars, Except Per Common Share Amounts)	2009	2008
INCOME		
Operating Revenues	$1,411,808	$1,454,121
Operating Expenses		
Purchased Gas	814,201	809,448
Operation and Maintenance	219,784	223,040
Property, Franchise and Other Taxes	39,134	39,070
Depreciation, Depletion and Amortization	84,056	86,533
Impairment of Oil and Gas Producing Properties	182,811	-
	1,339,986	1,158,091
Operating Income	71,822	296,030
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	288	3,305
Interest Income	2,898	5,270
Other Income	5,795	3,334
Interest Expense on Long-Term Debt	(35,601)	(32,577)
Other Interest Expense	(2,474)	(3,010)
Income Before Income Taxes	42,728	272,352
Income Tax Expense	11,922	106,744
Net Income Available for Common Stock	30,806	165,608
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	953,799	983,776
	984,605	1,149,384
Share Repurchases	-	(89,564)
Cumulative Effect of the Adoption of FIN 48	-	(406)
Adoption of SFAS 158 Measurement Date Provision	(804)	-
Dividends on Common Stock		
(2009 - $0.65 per share; 2008 - $0.62 per share)	(51,682)	(51,330)
Balance at March 31	$932,119	$1,008,084

Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$0.39	$1.98
Diluted:		
Net Income Available for Common Stock	$0.38	$1.93
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	79,400,660	83,509,268
Used in Diluted Calculation	80,156,407	85,603,033

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	March 31, 2009	September 30, 2008
ASSETS		
Property, Plant and Equipment	$5,032,215	$4,873,969
Less - Accumulated Depreciation, Depletion and Amortization	1,973,743	1,719,869
	3,058,472	3,154,100
Current Assets		
Cash and Temporary Cash Investments	86,048	68,239
Hedging Collateral Deposits	22,195	1
Receivables Net of Allowance for Uncollectible Accounts of $54,299 and $33,117, Respectively	304,500	185,397
Unbilled Utility Revenue	55,070	24,364
Gas Stored Underground	15,950	87,294
Materials and Supplies at average cost	24,257	31,317
Unrecovered Purchased Gas Costs	2,926	37,708
Other Current Assets	53,718	65,158
Deferred Income Taxes	26,197	-
	590,861	499,478
Other Assets		
Recoverable Future Taxes	83,541	82,506
Unamortized Debt Expense	13,029	13,978
Other Regulatory Assets	189,394	189,587
Deferred Charges	2,196	4,417
Other Investments	67,335	80,640
Investments in Unconsolidated Subsidiaries	13,667	16,279
Goodwill	5,476	5,476
Intangible Assets	25,123	26,174
Prepaid Post-Retirement Benefit Costs	21,447	21,034
Fair Value of Derivative Financial Instruments	112,723	28,786
Other	12,273	7,732
	546,204	476,609
Total Assets	$4,195,537	$4,130,187

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	March 31, 2009	September 30, 2008
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value Authorized - 200,000,000 Shares; Issued And Outstanding 79,514,816 Shares and 79,120,544 Shares, Respectively	$79,515	$79,121
Paid in Capital	581,189	567,716
Earnings Reinvested in the Business	932,119	953,799
Total Common Shareholder Equity Before Items of Other Comprehensive Income	1,592,823	1,600,636
Accumulated Other Comprehensive Income	44,171	2,963
Total Comprehensive Shareholders Equity	1,636,994	1,603,599
Long-Term Debt, Net of Current Portion	999,000	999,000
Total Capitalization	2,635,994	2,602,599
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	-	-
Current Portion of Long-Term Debt	-	100,000
Accounts Payable	105,048	142,520
Amounts Payable to Customers	21,650	2,753
Dividends Payable	25,841	25,714
Interest Payable on Long-Term Debt	21,397	22,114
Customer Advances	1,828	33,017
Other Accruals and Current Liabilities	246,291	45,220
Deferred Income Taxes	-	1,871
Fair Value of Derivative Financial Instruments	11,084	1,362
	433,139	374,571
Deferred Credits		
Deferred Income Taxes	606,893	634,372
Taxes Refundable to Customers	18,456	18,449
Unamortized Investment Tax Credit	4,340	4,691
Cost of Removal Regulatory Liability	105,855	103,100

Other Regulatory Liabilities	105,874	91,933
Pension and Other Post-Retirement Liabilities	67,203	78,909
Asset Retirement Obligations	90,954	93,247
Other Deferred Credits	126,829	128,316
	1,126,404	1,153,017
Commitments and Contingencies	-	-
Total Capitalization and Liabilities	$4,195,537	$4,130,187

See Notes to Condensed Consolidated Financial Statements

-9-

Table of Contents

Item 1. Financial Statements (Cont.)

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

(Thousands of Dollars)	Six Months Ended March 31, 2009	2008
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$30,806	$165,608
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	84,056	86,533
Deferred Income Taxes	(80,857)	12,817
Income from Unconsolidated Subsidiaries, Net of Cash Distributions	808	1,651
Impairment of Investment in Partnership	1,804	-
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(5,927)	(16,275)
Other	6,611	(194)
Change in:		
Hedging Collateral Deposits	(22,194)	1,712
Receivables and Unbilled Utility Revenue	(149,895)	(245,912)
Gas Stored Underground and Materials and Supplies	79,128	44,734
Unrecovered Purchased Gas Costs	34,782	13,347
Prepayments and Other Current Assets	16,954	15,878
Accounts Payable	(45,186)	39,838
Amounts Payable to Customers	18,897	(5,424)
Customer Advances	(31,189)	(22,863)
Other Accruals and Current Liabilities	216,249	192,787
Other Assets	2,399	18,127
Other Liabilities	(4,301)	4,504
Net Cash Provided by Operating Activities	335,756	306,868
INVESTING ACTIVITIES		
Capital Expenditures	(178,772)	(144,707)
Cash Held in Escrow	-	58,397
Net Proceeds from Sale of Oil and Gas Producing Properties	60	2,313
Other	(595)	1,557
Net Cash Used in Investing Activities	(179,307)	(82,440)
FINANCING ACTIVITIES		
Excess Tax Benefits Associated with Stock-Based Compensation Awards	5,927	16,275
Shares Repurchased under Repurchase Plan	-	(108,941)
Reduction of Long-Term Debt	(100,000)	(24)

Dividends Paid on Common Stock	(51,556)	(51,896)
Net Proceeds from Issuance of Common Stock	6,989	11,764
Net Cash Used in Financing Activities	(138,640)	(132,822)
Net Increase in Cash and Temporary Cash Investments	17,809	91,606
Cash and Temporary Cash Investments at October 1	68,239	124,806
Cash and Temporary Cash Investments at March 31	$86,048	$216,412

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

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

(Thousands of Dollars)	Three Months Ended March 31, 2009	2008
Net Income Available for Common Stock	$73,484	$95,004
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	34	(56)
Unrealized Loss on Securities Available for Sale Arising During the Period	(2,945)	(2,014)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	32,923	(47,713)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(39,615)	6,741
Other Comprehensive Loss, Before Tax	(9,603)	(43,042)
Income Tax Benefit Related to Unrealized Loss on Securities Available for Sale Arising During the Period	(1,113)	(761)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	13,399	(19,516)
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gains) Losses from Derivative Financial Instruments In Net Income	(15,959)	2,816
Income Taxes Net	(3,673)	(17,461)
Other Comprehensive Loss	(5,930)	(25,581)
Comprehensive Income	$67,554	$69,423

(Thousands of Dollars)	Six Months Ended March 31, 2009	2008
Net Income Available for Common Stock	$30,806	$165,608
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	42	(74)
Unrealized Loss on Securities Available for Sale Arising During the Period	(12,977)	(3,215)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	151,802	(68,572)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(68,407)	12,161

Other Comprehensive Income (Loss), Before Tax	70,460	(59,700)
Income Tax Benefit Related to Unrealized Loss on Securities Available for Sale Arising During the Period	(4,904)	(821)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	61,526	(28,164)
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gains) Losses from Derivative Financial Instruments In Net Income	(27,370)	4,949
Income Taxes Net	29,252	(24,036)
Other Comprehensive Income (Loss)	41,208	(35,664)
Comprehensive Income	$72,014	$129,944

See Notes to Condensed Consolidated Financial Statements

-11-

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.

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, 2008, 2007 and 2006 that are included in the Company s 2008 Form 10-K. The consolidated financial statements for the year ended September 30, 2009 will be audited by the Company s independent registered public accounting firm after the end of the fiscal year.

The earnings for the six months ended March 31, 2009 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2009. 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 March 31, 2009, the Company accrued $7.7 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. The Company also accrued $0.9 million of capital expenditures at March 31, 2009 related to the completion of the Empire Connector project. These amounts were excluded from the Consolidated Statement of Cash Flows at March 31, 2009 since they represent non-cash investing activities at that date.

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 six months ended March 31, 2009.

Hedging Collateral Deposits. This is an account title for cash held in margin accounts funded by the Company to serve as collateral for open positions on exchange-traded futures contracts and over-the-counter swap agreements.

At March 31, 2009, the Company had hedging collateral deposits of $22.2 million related to its exchange-traded futures contracts. The Company s over-the-counter swap agreements were in a significant asset position at March 31, 2009. Under the terms of those agreements, the Company was not required to fund any cash as hedging collateral; rather, the counterparties were required to provide

Item 1. Financial Statements (Cont.)

collateral to the Company. The amount of the collateral received was $11.9 million. This amount is included in Accounts Payable on the Consolidated Balance Sheet at March 31, 2009. It is the Company s policy to not offset hedging collateral deposits paid or received against the derivative financial instruments liability or asset balances.

Cash Held in Escrow. On August 31, 2007, the Company received approximately $232.1 million of proceeds from the sale of SECI, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. The escrow account was a Canadian dollar denominated account. On a U.S. dollar basis, the value of this account was $62.0 million at September 30, 2007. In December 2007, the Canadian government issued the tax clearance certificate, thereby releasing the proceeds from restriction as of December 31, 2007. To hedge against foreign currency exchange risk related to the cash being held in escrow, the Company held a forward contract to sell Canadian dollars. For presentation purposes on the Consolidated Statement of Cash Flows, for the six months ended March 31, 2008, the Cash Held in Escrow line item within Investing Activities reflects the net proceeds to the Company (received on January 8, 2008) after adjusting for the impact of the foreign currency hedge.

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 $171.0 million at March 31, 2009, is reduced to zero by September 30 of each year as the inventory is replenished.

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

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

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

Item 1. **Financial Statements (Cont.)**

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

	At March 31, 2009	At September 30, 2008
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (19,741)	$(19,741)
Cumulative Foreign Currency Translation Adjustment	(29)	(71)
Net Unrealized Gain on Derivative Financial Instruments	65,188	15,949
Net Unrealized Gain (Loss) on Securities Available for Sale [(1)]	(1,247)	6,826
Accumulated Other Comprehensive Income	$44,171	$2,963

[(1)] Includes a balanced equity mutual fund that is in an unrealized loss position of $3.9 million ($2.4 million after taxes) and $1.1 million ($0.7 million after taxes) at March 31, 2009 and September 30, 2008, respectively. The fair value of this investment was $10.2 million at March 31, 2009 and $12.4 million at September 30, 2008. This investment has been in an unrealized loss position for less than twelve months. Based on this fact and the fact that management has the intent and ability to hold the investment for a sufficient period of time for the asset to recover in value, management does not consider this investment to be other than temporarily impaired.

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 stock-settled 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 stock-settled SARs as determined using the Treasury Stock Method. Stock options and stock-settled SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For both the quarter and six months ended March 31, 2009, there were 765,000 stock options excluded as being antidilutive. In addition, there were 402,858 and 365,000 stock-settled SARs excluded as being antidilutive for the quarter and six months ended March 31, 2009, respectively. For the quarter and six months ended March 31, 2008, there were 131,110 and 65,197 stock-settled SARs, respectively, excluded as being antidilutive. There were no stock options excluded as being antidilutive for the quarter and six months ended March 31, 2008.

Share Repurchases. The Company considers all shares repurchased as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. The repurchases are accounted for on the date the share repurchase is settled as an adjustment to common stock (at par value) with the excess repurchase price allocated between paid in capital and retained earnings.

Stock-Based Compensation. During the six months ended March 31, 2009, the Company granted 610,000 performance-based stock-settled SARs having a weighted average exercise price of $29.88 per share. The weighted average grant date fair value of these stock-settled SARs was $4.09 per share. There were no stock-settled SARs granted during the quarter ended March 31, 2009. The accounting treatment for such stock-settled SARs is the same under SFAS 123R as the accounting for stock options under SFAS 123R. The stock-settled SARs granted during the six months ended March 31, 2009 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 stock-settled SARs granted during the six months ended March 31, 2009 was estimated on the date of grant using the same accounting treatment that is

Item 1. Financial Statements (Cont.)

applied for stock options under SFAS 123R, 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 or restricted share awards (non-vested stock as defined in SFAS 123R) granted during the quarter and six months ended March 31, 2009.

New Accounting Pronouncements. In September 2006, the FASB issued SFAS 157, Fair Value Measurements . SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement 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. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. In accordance with FASB Staff Position FAS No. 157-2, on October 1, 2008, the Company adopted SFAS 157 for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. The same FASB Staff Position delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value on a recurring basis, until the Company s first quarter of fiscal 2010. For further discussion of the impact of the adoption of SFAS 157 for financial assets and financial liabilities, refer to Note 2 Fair Value Measurements. The Company is currently evaluating the impact that the adoption of SFAS 157 for nonfinancial assets and nonfinancial liabilities will have on its consolidated financial statements. The Company has identified Goodwill as being the major nonfinancial asset that may be impacted by the adoption of SFAS 157. The Company does not believe there are any nonfinancial liabilities that will be impacted by the adoption of SFAS 157.

In September 2006, the FASB issued SFAS 158, Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans (an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R). SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan s assets and obligations that determine its funded status be measured as of the end of the Company s fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be fully adopted by the Company by the end of fiscal 2009. The Company has historically measured its plan assets and benefit obligations using a June 30th measurement date. In anticipation of changing to a September 30th measurement date, the Company will be recording fifteen months of pension and other post-retirement benefit costs during fiscal 2009. In accordance with the provisions of SFAS 158, these costs have been calculated using June 30, 2008 measurement date data. Three of those months pertain to the period of July 1, 2008 to September 30, 2008. The pension and other post-retirement benefit costs for that period amounted to $5.1 million and have been recorded by the Company during the quarter ended December 31, 2008 as a $3.8 million increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $1.3 million ($0.8 million after tax) adjustment to earnings reinvested in the business. For further discussion of the impact of adopting the measurement date provisions of SFAS 158, refer to Note 9 Retirement Plan and Other Post-Retirement Benefits.

In December 2007, the FASB issued SFAS 141R, Business Combinations. SFAS 141R will significantly change the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under SFAS 141R, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. SFAS 141R is effective as of the Company s first quarter of fiscal 2010.

Table of Contents

Item 1. Financial Statements (Cont.)

In December 2007, the FASB issued SFAS 160, Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. SFAS 160 is effective as of the Company s first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued SFAS 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133. SFAS 161 requires entities to provide enhanced disclosures related to an entity s derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity s financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The Company adopted the disclosure provisions of SFAS 161 during the quarter ended March 31, 2009. These disclosures may be found at Note 3 Derivative Financial Instruments.

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

In April 2009, the FASB issued FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments. This FASB Staff Position amends SFAS 107, Disclosures about Fair Value of Financial Instruments, to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. These disclosures will be required in the Company s Form 10-Q for the period ended June 30, 2009.

Note 2 Fair Value Measurements

Beginning in fiscal 2009, the Company adopted the provisions of SFAS 157, Fair Value Measurements. SFAS 157 establishes a fair-value hierarchy, which 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 adoption of SFAS 157 has not had a significant impact on the consolidated financial statements.

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2009. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Table of Contents

Item 1. Financial Statements (Cont.)

Recurring Fair Value Measures	At fair value as of March 31, 2009			
(Dollars in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Cash Equivalents	$60,922	$ -	$ -	$60,922
Derivative Financial Instruments	-	33,564	79,159	112,723
Other Investments	14,770	-	-	14,770
Hedging Collateral Deposits	22,195	-	-	22,195
Total	$97,887	$ 33,564	$ 79,159	$210,610
Liabilities:				
Derivative Financial Instruments	$ 11,084	$ -	$ -	$ 11,084
Total	$ 11,084	$ -	$ -	$ 11,084

Cash Equivalents

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

Derivative Financial Instruments

The derivative financial instruments reported in Level 1 consist of NYMEX futures contracts. The hedging collateral deposits 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 swap agreements used in the Company s Exploration and Production segment and natural gas swap agreements used in the Energy Marketing segment. The fair value of these natural gas price swap agreements is based on an internal model that uses observable inputs. The fair market value of the price swap agreements reported in Level 2 as assets has been reduced by $0.8 million based on an assessment of counterparty credit risk. The derivative financial instruments reported in Level 3 consist of all of the Exploration and Production segment s crude oil swap agreements and some of its natural gas swap agreements. The fair value of the crude oil and natural gas price swap agreements is based on an internal model that uses both observable and unobservable inputs. The fair market value of the price swap agreements reported in Level 3 as assets has been reduced by $2.3 million based on an assessment of counterparty credit risk. This credit reserve, as well as the credit reserve established for the Level 2 price swap agreement assets, was 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.

Other Investments

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

The table listed below provides a reconciliation of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3.

Table of Contents

Item 1. Financial Statements (Cont.)

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Dollars in thousands)	October 1, 2008	Total Gains/Losses Realized and Unrealized Included in Earnings	Included in Other Comprehensive Income	Transfer In/Out of Level 3	March 31, 2009
Assets:					
Derivative Financial Instruments	$7,110	$(23,677)[(1)]	$95,726	$ -	$79,159
Total	$7,110	$(23,677)	$95,726	$ -	$79,159
Liabilities:					
Derivative Financial Instruments	$(777)	$(12,104)[(1)]	$12,881	$ -	$ -
Total	$(777)	$(12,104)	$12,881	$ -	$ -

[(1)] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the six months ended March 31, 2009.

Note 3 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 and Energy Marketing 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, and withdrawal of gas from storage to meet customer demand. The duration of the Company s hedges do not typically exceed 3 years and the majority of the positions settle within one year.

In accordance with the adoption of SFAS 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133 , the Company has presented its gross derivative assets and liabilities in the table below.

Fair Values of Derivative Instruments
(Dollar Amounts in Thousands)

	Asset Derivatives March 31, 2009		Liability Derivatives March 31, 2009	
Derivatives Designated as Hedging Instruments under SFAS 133	**Consolidated Balance Sheet Location**	**Fair Value**	**Consolidated Balance Sheet Location**	**Fair Value**
Commodity Contracts	Fair Value of Derivative Financial Instruments	$112,723 (1)	Fair Value of Derivative Financial Instruments	$11,084 (2)

(1) Agrees to the sum of Level 2 and Level 3 Derivative Financial Instrument Assets shown in Note 2, Fair Value Measurements.
(2) Agrees to the Level 1 Derivative Financial Instrument Liabilities shown in Note 2, Fair Value Measurements.

Item 1. Financial Statements (Cont.)

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 and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of March 31, 2009, the Company s Exploration and Production segment had the following commodity derivative contracts (swaps) outstanding to hedge forecasted sales (where the Company uses short positions (i.e. positions that pay-off in the event of commodity price decline) to mitigate the risk of decreasing revenues and earnings):

Commodity	Units
Natural Gas	16.2 Bcf (all short positions)
Crude Oil	1,290,000 Bbls (all short positions)

As of March 31, 2009, the Company s Energy Marketing segment had the following commodity derivative contracts (futures contracts and swaps) outstanding to hedge forecasted sales (where the Company uses short positions to mitigate the risk associated with natural gas price decreases and its impact on decreasing revenues and earnings) and purchases (where the Company uses long positions (i.e. positions that pay-off in the event of commodity price increases) to mitigate the risk of increasing natural gas prices, which would lead to increased purchased gas expense and decreased earnings):

Commodity	Units
Natural Gas	9.7 Bcf (5.4 Bcf short positions (forecasted storage withdrawals) and 4.3 Bcf long positions (forecasted storage injections))

As of March 31, 2009, the Company s Exploration and Production segment had $109.5 million ($64.8 million after tax) of gains included in the accumulated other comprehensive income balance. It it expected that $75.1 million ($44.5 million after tax) of these gains will be reclassified into income within the next 12 months as the sales of the underlying commodities are expected to occur. See Note 1, under Accumulated Other Comprehensive Income, for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note 1 includes both the Exploration and Production and Energy Marketing segments).

As of March 31, 2009, the Company s Energy Marketing segment had $0.6 million ($0.4 million after tax) of gains included in the accumulated other comprehensive income balance. It it expected that $0.6 million ($0.4 million after tax) of these gains will be reclassified into income within the next 12 months as the sales and purchases of the underlying commodities occur. See Note 1, under Accumulated Other Comprehensive Income, for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note 1 includes both the Exploration and Production and Energy Marketing segments).

Table of Contents

Item 1. Financial Statements (Cont.)

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

Derivatives in SFAS 133 Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income on the Consolidated Statement of Comprehensive Income (Effective Portion) for the Six Months Ended March 31, 2009	Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income 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 on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for Six Months Ended March 31, 2009	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Six Months Ended March 31, 2009
Commodity Contracts Exploration & Production segment	$140,777	Operating Revenue	$48,384	Operating Revenue	$(266)
Commodity Contracts Energy Marketing segment	$10,842	Purchased Gas	$19,415	Operating Revenue	$ -
Commodity Contracts Pipeline & Storage segment (1)	$ -	Operating Revenue	$1,290	Operating Revenue	$ -
	$183	Purchased Gas	$(682)	Purchased Gas	$ -

Commodity Contracts All Other [1]			
Total	$151,802	$68,407	$(266)

[1] There were no open hedging positions at March 31, 2009. As such there is no mention of these positions in the preceeding sections of this footnote.

Fair value hedges

The Company s Energy Marketing segment is the only segment which utilizes fair value hedges to mitigate risk associated with fixed prices sales commitments, fixed price purchase commitments, and commitments related to the injection and withdrawal of storage gas. In order to hedge fixed price sales commitments, the Company enters into long positions to mitigate the risk that after the Company locks into fixed price sales agreements with its customers, the price of natural gas increases (thereby passing up the opportunity for higher operating revenue). With fixed price purchase commitments, the risk is that

-20-

Table of Contents

Item 1. Financial Statements (Cont.)

after the Company locks into fixed price purchase deals with its suppliers, the price of natural gas decreases (thereby passing up the opportunity for lower purchased gas expense). Fair value hedges related to the injection and withdrawal of storage gas impact purchased gas expense. As of March 31, 2009, the Company s Energy Marketing segment had fair value hedges covering approximately 11.7 Bcf (9.7 Bcf of fixed price sales commitments (all long positions), 1.9 Bcf of fixed price purchase commitments (all short positions), and 0.1 Bcf of commitments related to the withdrawal of storage gas (all short positions)). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Consolidated Statement of Income	Gain/(Loss) on Derivative	Gain/(Loss) on Commitment
Operating Revenues	$(6,146,915)	$6,146,915
Purchased Gas	$(4,140,875)	$4,140,875

Derivatives in SFAS 133 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 Six Months Ended March 31, 2009 (In Thousands)
Commodity Contracts Energy Marketing segment (1)	Operating Revenues	$(6,147)
Commodity Contracts Energy Marketing segment (2)	Purchased Gas	$4,013
Commodity Contracts Energy Marketing segment (3)	Purchased Gas	$(8,154)
		$(10,288)

(1) Represents hedging of fixed price sales commitments of natural gas.
(2) Represents hedging of fixed price purchase commitments of natural gas.
(3) Represents hedging of storage withdrawal commitments of natural gas.

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risks relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company s counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with ten counterparties. The Company has $56.3 million of credit exposure with one counterparty. However, the credit exposure is partially mitigated by $11.9 million of cash collateral that the Company received from the counterparty. (This is discussed in Note 1 under Hedging Collateral Deposits.) On average, the Company has $6.2 million of credit exposure per counterparty with the other nine counterparties (the Company has not received any collateral from these nine counterparties).

As of March 31, 2009, seven of the ten counterparties to the Company s outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk-related contingency feature. In the event the Company s credit rating increases or falls below a certain threshold (the lower of the S&P or Moody s Debt Rating), the available credit extended to the Company would either increase or decrease. A change 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 deteriorated, then additional hedging collateral deposits would be required. At March 31, 2009, these credit-risk related contingency features would not have been triggered since the Company had assets of $96.0 million related to derivative financial instruments with the seven counterparties.

Table of Contents

Item 1. Financial Statements (Cont.)

For its exchange traded futures contracts, which are in a liability position to the Company, the Company had paid $22.2 million in hedging collateral as of March 31, 2009. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions (i.e. those positions that have been settled for cash) and margin requirements. (This is discussed in Note 1 under Hedging Collateral Deposits.)

Note 4 - Income Taxes

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

	Six Months Ended March 31,	
	2009	2008
Current Income Taxes		
Federal	$73,235	$76,567
State	19,543	17,270
Foreign	-	90
Deferred Income Taxes		
Federal	(64,045)	6,223
State	(16,811)	6,594
	11,922	106,744
Deferred Investment Tax Credit	(348)	(348)
Total Income Taxes	$11,574	$106,396
Presented as Follows:		
Other Income	$(348)	$(348)
Income Tax Expense	11,922	106,744
Total Income Taxes	$11,574	$106,396

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):

	Six Months Ended March 31,	
	2009	2008
U.S. Income Before Income Taxes	$42,380	$272,004
Income Tax Expense, Computed at Federal Statutory Rate of 35%	$14,833	$95,201

Increase (Reduction) in Taxes Resulting From:		
State Income Taxes	1,776	15,512
Allowance for Funds Used During Construction	(1,072)	(525)
ESOP Dividend Deduction	(1,050)	(1,050)
Reduced Tax Rate on Timber Gains	(920)	-
Keyman Life Insurance Proceeds	(824)	(66)
Miscellaneous	(1,169)	(2,676)
Total Income Taxes	$11,574	$106,396

-22-

Item 1. Financial Statements (Cont.)

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

	At March 31, 2009	At September 30, 2008
Deferred Tax Liabilities:		
Property, Plant and Equipment	$623,312	$673,313
Pension and Other Post-Retirement Benefit Costs SFAS 158	44,345	43,340
Unrealized Hedging Gains	44,194	14,936
Other	25,351	40,455
Total Deferred Tax Liabilities	737,202	772,044
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs SFAS 158	(44,345)	(43,340)
Other	(112,161)	(92,461)
Total Deferred Tax Assets	(156,506)	(135,801)
Total Net Deferred Income Taxes	$580,696	$636,243
Presented as Follows:		
Net Deferred Tax Liability/(Asset) Current	$(26,197)	$1,871
Net Deferred Tax Liability Non-Current	606,893	634,372
Total Net Deferred Income Taxes	$580,696	$636,243

Regulatory liabilities representing the reduction of previously recorded deferred income taxes with rate-regulated activities that are expected to be refundable to customers amounted to $18.5 million at March 31, 2009 and $18.4 million at September 30, 2008, 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 $83.5 million and $82.5 million at March 31, 2009 and September 30, 2008, respectively.

The Company files U.S. federal and various state income tax returns. The Internal Revenue Service (IRS) is currently conducting an examination of the Company for fiscal 2008 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 2005 and later years, IRS examinations for fiscal 2007 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 March 31, 2009, the Company does not have any unrecognized tax benefits. During the three months ended March 31, 2009, unrecognized tax benefits related to uncertain tax positions decreased by $1.7 million, reflecting reductions to uncertain tax positions for settlements with and payments to tax authorities.

Note 5 Capitalization

Common Stock. During the six months ended March 31, 2009, the Company issued 687,180 original issue shares of common stock as a result of stock option exercises. The Company also issued 4,200 original issue shares of common stock to the seven 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 six months ended March 31, 2009. Holders of stock options or restricted stock will often tender shares of common stock to the Company for payment of option exercise

Item 1. Financial Statements (Cont.)

prices and/or applicable withholding taxes. During the six months ended March 31, 2009, 297,108 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.

Shareholder Rights Plan. In 1996, the Company s Board of Directors adopted a shareholder rights plan (Plan). The Plan has been amended several times since it was adopted and is now embodied in an Amended and Restated Rights Agreement effective December 4, 2008, a copy of which was included as an exhibit to the Form 8-K filed by the Company on December 4, 2008.

Pursuant to the Plan, the holders of the Company s common stock have one right (Right) for each of their shares. Each Right is initially evidenced by the Company s common stock certificates representing the outstanding shares of common stock.

The Rights have anti-takeover effects because they will cause substantial dilution of the Company s common stock if a person attempts to acquire the Company on terms not approved by the Board of Directors (an Acquiring Person).

The Rights become exercisable upon the occurrence of a Distribution Date as described below, but after a Distribution Date Rights that are owned by an Acquiring Person will be null and void. At any time following a Distribution Date, each holder of a Right may exercise its right to receive, upon payment of an amount calculated under the Rights Agreement, common stock of the Company (or, under certain circumstances, other securities or assets of the Company) having a value equal to two times the amount paid to exercise the Right. However, the Rights are subject to redemption or exchange by the Company prior to their exercise as described below.

A Distribution Date would occur upon the earlier of (i) ten days after the public announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of the Company s common stock or other voting stock (including Synthetic Long Positions as defined in the Plan) having 10% or more of the total voting power of the Company s common stock and other voting stock and (ii) ten days after the commencement or announcement by a person or group of an intention to make a tender or exchange offer that would result in that person acquiring, or obtaining the right to acquire, beneficial ownership of the Company s common stock or other voting stock having 10% or more of the total voting power of the Company s common stock and other voting stock.

In certain situations after a person or group has acquired beneficial ownership of 10% or more of the total voting power of the Company s stock as described above, each holder of a Right will have the right to exercise its Rights to receive, upon exercise of the right, common stock of the acquiring company having a value equal to two times the amount paid to exercise the right. These situations would arise if the Company is acquired in a merger or other business combination or if 50% or more of the Company s assets or earning power are sold or transferred.

At any time prior to the end of the business day on the tenth day following the Distribution Date, the Company may redeem the Rights in whole, but not in part, at a price of $0.005 per Right, payable in cash or stock. A decision to redeem the Rights requires the vote of 75% of the Company s full Board of Directors. Also, at any time following the Distribution Date, 75% of the Company s full Board of Directors may vote to exchange the Rights, in whole or in part, at an exchange rate of one share of common stock, or other property deemed to have the same value, per Right, subject to certain adjustments.

Upon exercise of the Rights, the Company may need additional regulatory approvals to satisfy the requirements of the Rights Agreement. The Rights will expire on July 31, 2018, unless earlier than that date, they are exchanged or redeemed or the Plan is amended to extend the expiration date.

Table of Contents

Item 1. Financial Statements (Cont.)

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.

As disclosed in Note H of the Company s 2008 Form 10-K, 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 $16.1 million.

At March 31, 2009, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be in the range of $19.0 million to $23.2 million. The minimum estimated liability of $19.0 million, which includes the $16.1 million discussed above, has been recorded on the Consolidated Balance Sheet at March 31, 2009. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet.

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

Other. The Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company s present liquidity position, or have a material adverse effect on the financial condition of the Company.

Table of Contents

Item 1. Financial Statements (Cont.)

Note 7 Business Segment Information

In the Company s 2008 Form 10-K, the Company reported financial results for five business segments: Utility, Pipeline and Storage, Exploration and Production, Energy Marketing and Timber. 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. During the quarter ended December 31, 2008, management made the decision to eliminate the Timber segment as a reportable segment based on the fact that the Timber operations do not meet any of the quantitative thresholds specified by SFAS 131. Furthermore, from a qualitative standpoint, management s focus has changed regarding the Timber operations. While the Timber segment will continue to harvest hardwood timber and process lumber products that are used in high-end furniture, cabinetry and flooring, management no longer considers the Timber operations to be integral to the overall operations of the Company. As a result of this change in focus and the fact that the Timber operations cannot be aggregated into one of the other four reportable business segments, the Timber operations have been included in the All Other category in the disclosures that follow. Prior year segment information shown below has been restated to reflect this change in presentation. In addition, refer to the Company s Form 8-K filed on March 17, 2009 that updates its historical business segment information contained in the Company s 2008 Form 10-K to reflect the change in reportable segments.

The data presented in the tables below reflect the reportable segments and reconciliations to consolidated amounts. As stated in the 2008 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (where 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, other than as noted above, nor in the basis of measuring segment profit or loss from those used in the Company s 2008 Form 10-K. There have been no material changes in the amount of assets for any operating segment from the amounts disclosed in the 2008 Form 10-K. While the Exploration and Production segment reported a pre-tax impairment charge of $182.8 million during the six months ended March 31, 2009, this reduction in segment assets was largely offset by increases in the asset position of its derivative financial instruments combined with the receipts of cash collateral on such derivative financial instruments.

Table of Contents

Item 1. Financial Statements (Cont.)

Quarter Ended March 31, 2009 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$502,016	$39,846	$ 87,077	$163,545	$ 792,484	$11,929	$ 232	$ 804,645
Intersegment Revenues	$ 5,846	$21,156	$ -	$ -	$ 27,002	$1,194	$(28,196)	$ -
Segment Profit: Net Income (Loss)	$ 32,819	$15,186	$ 18,107	$ 5,579	$ 71,691	$1,907	$ (114)	$ 73,484

Six Months Ended March 31, 2009 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$851,653	$75,113	$183,790	$278,551	$1,389,107	$22,254	$ 447	$1,411,808
Intersegment Revenues	$ 10,399	$41,993	$ -	$ -	$ 52,392	$3,516	$(55,908)	$ -
Segment Profit: Net Income (Loss)	$ 54,907	$32,362	$ (65,450)	$ 6,178	$ 27,997	$1,040	$ 1,769	$ 30,806

Quarter Ended March 31, 2008 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$522,730	$37,934	$114,720	$191,263	$ 866,647	$19,043	$ 163	$ 885,853
Intersegment Revenues	$ 6,114	$20,861	$ -	$ -	$ 26,975	$3,099	$(30,074)	$ -

Segment Profit: Net Income (Loss)	$ 34,164	$15,618	$ 34,572	$ 5,647	$ 90,001	$5,575	$ (572)	$ 95,004

Six Months Ended March 31, 2008 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$849,855	$69,817	$222,675	$277,982	$1,420,329	$33,493	$ 299	$1,454,121
Intersegment Revenues	$ 10,413	$41,209	$ -	$ -	$ 51,622	$ 5,812	$(57,434)	$ -
Segment Profit: Net Income (Loss)	$ 54,380	$28,397	$ 68,594	$ 6,602	$ 157,973	$ 8,310	$ (675)	$ 165,608

Item 1. Financial Statements (Cont.)
Note 8 - Intangible Assets

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

	At March 31, 2009			At September 30, 2008
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount
Intangible Assets Subject to Amortization:				
Long-Term Transportation Contracts	$ 8,580	$(6,312)	$ 2,268	$ 2,522
Long-Term Gas Purchase Contracts	31,864	(9,009)	22,855	23,652
	$40,444	$(15,321)	$25,123	$ 26,174

Aggregate Amortization Expense:	
(Thousands)	
Three Months Ended March 31, 2009	$497
Three Months Ended March 31, 2008	$666
Six Months Ended March 31, 2009	$1,051
Six Months Ended March 31, 2008	$1,331

The gross carrying amount of intangible assets subject to amortization at March 31, 2009 remained unchanged from September 30, 2008. 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 $0.2 million for the remainder of 2009 and $0.4 million annually for 2010, 2011, 2012 and 2013. Amortization expense for the long-term gas purchase contracts is estimated to be $0.8 million for the remainder of 2009 and $1.6 million annually for 2010, 2011, 2012 and 2013.

Note 9 Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

Three months ended March 31,

	Retirement Plan		Other Post-Retirement Benefits	
	2009	2008	2009	2008
Service Cost	$2,728	$3,149	$950	$1,276
Interest Cost	11,709	11,238	6,875	6,770
Expected Return on Plan Assets	(14,489)	(13,750)	(7,904)	(8,429)
Amortization of Prior Service Cost	183	202	(268)	1
Amortization of Transition Amount	-	-	566	1,782
Amortization of Losses	1,419	2,766	2,318	732
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	7,358	5,714	8,015	8,462

Net Periodic Benefit Cost	$8,908	$9,319	$10,552	$10,594

Table of Contents

Item 1. Financial Statements (Concl.)
Six months ended March 31,

	Retirement Plan		Other Post-Retirement Benefits	
	2009	2008	2009	2008
Service Cost	$5,456	$6,299	$1,901	$2,552
Interest Cost	23,418	22,475	13,750	13,541
Expected Return on Plan Assets	(28,979)	(27,500)	(15,808)	(16,857)
Amortization of Prior Service Cost	366	404	(537)	2
Amortization of Transition Amount	-	-	1,133	3,563
Amortization of Losses	2,838	5,532	4,635	1,463
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	10,598	6,814	12,354	15,674
Net Periodic Benefit Cost	$13,697	$14,024	$17,428	$19,938

(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.

As indicated under New Accounting Pronouncements in Note 1 Summary of Significant Accounting Policies, in accordance with the measurement date provisions of SFAS 158 that specifies that a plan s assets and obligations that determine its funded status be measured as of the end of the Company s fiscal year, the Company will be recording fifteen months of pension and other post-retirement benefit costs during fiscal 2009. As allowed by SFAS 158, these costs have been calculated using June 30, 2008 measurement date data. Three of those months pertain 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 have been recorded by the Company during the six months ended March 31, 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 pension plan, benefit costs of $1.3 million have been recorded by the Company during the six months ended March 31, 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. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be fully adopted by the Company by the end of fiscal 2009.

Employer Contributions. During the six months ended March 31, 2009, the Company contributed $11.6 million to its retirement plan and $15.9 million to its VEBA trusts and 401 (h) accounts for its other post-retirement benefits. In the remainder of 2009, the Company expects to contribute in the range of $3 million to $8 million to its retirement plan. As a result of the recent downturn in the stock markets and general economic conditions, it is likely that the Company will have to fund larger amounts to the retirement plan subsequent to fiscal 2009 in order to be in compliance with the Pension Protection Act of 2006. In the remainder of 2009, the Company expects to contribute in the range of $9 million to $14 million to its VEBA trusts and 401(h) accounts.

Note 10 Subsequent Event

In April 2009, the Company issued $250.0 million of 8.75% notes due in May 2019. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $247.8 million. The holders of the notes may require the Company to repurchase their notes in the event of a change in control at a price equal to 101% of the principal amount. The proceeds of this debt issuance were used for general corporate purposes, including to replenish cash that was used to pay the $100 million due at the maturity of the Company s 6.0% medium-term notes on March 1, 2009.

Table of Contents

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

OVERVIEW

The Company is a diversified energy company consisting of four reportable business segments. For the quarter ended March 31, 2009 compared to the quarter ended March 31, 2008, the Company experienced a decrease in earnings of $21.5 million, primarily due to lower earnings in the Exploration and Production segment. For the six months ended March 31, 2009 compared to the six months ended March 31, 2008, the Company experienced a decrease in earnings of $134.8 million. The earnings decrease for the six 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. In the Company s Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Such costs are subject to a quarterly ceiling test prescribed by SEC Regulation S-X Rule 4-10 that determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. At December 31, 2008, due to significant declines in crude oil and natural gas commodity prices (Cushing, Oklahoma West Texas Intermediate oil reported spot price of $44.60 per Bbl at December 31, 2008 versus a reported price of $100.70 per Bbl at September 30, 2008; Henry Hub natural gas reported spot price of $5.63 per MMBtu at December 31, 2008 versus a reported price of $7.12 per MMBtu at September 30, 2008), the book value of the Company s oil and gas properties exceeded the ceiling, resulting in the impairment charge mentioned above. (Note Because actual pricing of the Company s various producing properties varies depending on their location, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Cushing oil and Henry Hub prices, which are only indicative.) At March 31, 2009, the quoted Cushing, Oklahoma spot price for West Texas Intermediate oil increased to $49.64 per Bbl and the quoted spot price for natural gas decreased to $3.63 per MMBtu. At March 31, 2009, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $37 million. While natural gas prices decreased significantly subsequent to December 31, 2008, the increase in crude oil prices subsequent to December 31, 2008 combined with a decrease in the basis differential between Cushing, Oklahoma West Texas Intermediate oil and Seneca s California oil reserves over the same period of time, prevented an impairment charge at March 31, 2009. If natural gas prices used in the ceiling test calculation at March 31, 2009 had been $1 per MMBtu lower, the Company would have recorded an impairment charge of approximately $17.8 million (after tax). If crude oil prices used in the ceiling test calculation at March 31, 2009 had been $5 per Bbl lower, the Company would have recorded an impairment charge of approximately $16.4 million (after tax). If both natural gas and crude oil prices used in the ceiling test calculation at March 31, 2009 were lower by $1 per MMBtu and $5 per Bbl, respectively, the Company would have recorded an impairment charge of approximately $71.4 million (after tax). These calculated impairment charges are based solely on price changes and do not take into account any other changes to the ceiling test calculation.

Despite the decrease in earnings discussed above, the Company s balance sheet consisted of a capitalization structure of 62% equity and 38% debt at March 31, 2009. In April 2009, the Company issued $250.0 million of 8.75% notes due in May 2019. While this issuance increases the debt portion of the Company s capitalization structure, management believes that it also enhances the Company s liquidity position at a time of uncertainty in the credit markets. Of the $247.8 million in net proceeds from the issuance, $100 million was used to replenish the cash used to repay $100 million of 6.0% medium-term notes that matured on March 1, 2009. The remainder was used for general corporate purposes. In addition to the proceeds from this debt issuance, the Company has been able to borrow short-term funds under its credit lines and through the commercial paper market to fund working capital needs throughout the first six months of 2009. At March 31, 2009, the Company did not have any short-term borrowings. However, the Company continues to maintain a number of individual uncommitted or discretionary lines of credit with financial institutions for general corporate purposes. 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.

Table of Contents

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

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to Critical Accounting Estimates in Item 7 of the Company s 2008 Form 10-K and Item 2 of the Company s December 31, 2008 Form 10-Q. There have been no material changes to those disclosures other than as set forth below. The information presented below updates 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 those reserves at the balance sheet date. If the book value of the reserves in any country exceeds the ceiling, a non-cash charge must be recorded to reduce the book value of the reserves to the calculated ceiling. As disclosed in the Company s 2008 Form 10-K, at September 30, 2008, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $500 million. Because of declines in commodity prices since September 30, 2008, the book value of the Company s oil and gas properties exceeded the ceiling at December 31, 2008. The quoted Cushing, Oklahoma spot price for West Texas Intermediate oil had declined from a reported price of $100.70 per Bbl at September 30, 2008 to a reported price of $44.60 per Bbl at December 31, 2008. The quoted Henry Hub spot price for natural gas had declined from a reported price of $7.12 per MMBtu at September 30, 2008 to a reported price of $5.63 per MMBtu at December 31, 2008. Consequently, the Company recorded an impairment charge of $182.8 million ($108.2 million after-tax) during the quarter ended December 31, 2008. (Note Because actual pricing of the Company s various producing properties varies depending on their location, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Cushing oil and Henry Hub prices, which are only indicative.) At March 31, 2009, the quoted Cushing, Oklahoma spot price for West Texas Intermediate oil increased to $49.64 per Bbl and the quoted spot price for natural gas decreased to $3.63 per MMBtu. At March 31, 2009, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $37 million. While natural gas prices decreased significantly subsequent to December 31, 2008, the increase in crude oil prices subsequent to December 31, 2008 combined with a decrease in the basis differential between Cushing, Oklahoma West Texas Intermediate oil and Seneca s California oil reserves over the same period of time, prevented an impairment charge at March 31, 2009. If natural gas prices used in the ceiling test calculation at March 31, 2009 had been $1 per MMBtu lower, the Company would have recorded an impairment charge of approximately $17.8 million (after tax). If crude oil prices used in the ceiling test calculation at March 31, 2009 had been $5 per Bbl lower, the Company would have recorded an impairment charge of approximately $16.4 million (after tax). If both natural gas and crude oil prices used in the ceiling test calculation at March 31, 2009 were lower by $1 per MMBtu and $5 per Bbl, respectively, the Company would have recorded an impairment charge of approximately $71.4 million (after tax). These calculated impairment charges 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 2008 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company s earnings were $73.5 million for the quarter ended March 31, 2009 compared to earnings of $95.0 million for the quarter ended March 31, 2008. The decrease in earnings of $21.5 million is primarily the result of lower earnings in the Exploration and Production segment. The Utility, Pipeline and Storage, and Energy Marketing segments, as well as the All Other category also contributed to the decrease in earnings. Higher earnings in the Corporate category slightly offset these decreases.

Table of Contents

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

The Company s earnings were $30.8 million for the six months ended March 31, 2009 compared to earnings of $165.6 million for the six months ended March 31, 2008. The decrease in earnings of $134.8 million is primarily the result of lower earnings in the Exploration and Production segment. The Energy Marketing segment and the All Other category also contributed to the decrease in earnings. Higher earnings in the Utility and Pipeline and Storage segments, as well as the Corporate category, slightly offset these decreases. The Company s earnings for the six months ended March 31, 2009 include 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 March 31,			Six Months Ended March 31,		
(Thousands)	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
Utility	$32,819	$34,164	$(1,345)	$54,907	$54,380	$527
Pipeline and Storage	15,186	15,618	(432)	32,362	28,397	3,965
Exploration and Production	18,107	34,572	(16,465)	(65,450)	68,594	(134,044)
Energy Marketing	5,579	5,647	(68)	6,178	6,602	(424)
Total Reportable Segments	71,691	90,001	(18,310)	27,997	157,973	(129,976)
All Other	1,907	5,575	(3,668)	1,040	8,310	(7,270)
Corporate	(114)	(572)	458	1,769	(675)	2,444
Total Consolidated	$73,484	$95,004	$(21,520)	$30,806	$165,608	$(134,802)

Utility

Utility Operating Revenues

	Three Months Ended March 31,			Six Months Ended March 31,		
(Thousands)	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
Retail Sales Revenues:						
Residential	$394,006	$393,269	$737	$666,424	$640,066	$ 26,358
Commercial	65,237	66,090	(853)	106,571	104,123	2,448
Industrial	3,920	3,924	(4)	6,026	5,575	451
	463,163	463,283	(120)	779,021	749,764	29,257
Transportation	40,929	42,337	(1,408)	72,939	75,761	(2,822)
Off-System Sales	8	19,855	(19,847)	3,740	28,067	(24,327)
Other	3,762	3,369	393	6,352	6,676	(324)

	$507,862	$528,844	$(20,982)	$862,052	$860,268	$1,784

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

	Three Months Ended March 31,			Six Months Ended March 31,		
(MMcf)	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
Retail Sales:						
Residential	28,366	28,136	230	46,533	45,263	1,270
Commercial	4,852	4,986	(134)	7,762	7,863	(101)
Industrial	302	323	(21)	445	446	(1)
	33,520	33,445	75	54,740	53,572	1,168
Transportation	24,256	26,054	(1,798)	41,729	43,881	(2,152)
Off-System Sales	1	2,048	(2,047)	513	3,080	(2,567)
	57,777	61,547	(3,770)	96,982	100,533	(3,551)

Degree Days

Three Months Ended				Percent Colder (Warmer) Than	
March 31	Normal	2009	2008	Normal	Prior Year
Buffalo	3,327	3,391	3,264	1.9	3.9
Erie	3,142	3,176	3,104	1.1	2.3
Six Months Ended March 31					
Buffalo	5,587	5,704	5,358	2.1	6.5
Erie	5,223	5,243	4,975	0.4	5.4

2009 Compared with 2008

Operating revenues for the Utility segment decreased $21.0 million for the quarter ended March 31, 2009 as compared with the quarter ended March 31, 2008. The decrease is primarily attributable to a $19.8 million decrease in off-system sales revenues combined with a $1.4 million decrease in transportation revenues. Despite colder weather, transportation revenues decreased due to conservation efforts and the poor economy. The decrease in off-system sales stems from Order No. 717 (Final Rule), which was issued by the FERC on October 16, 2008. The Final Rule seemingly holds that a local distribution company making off-system sales on unaffiliated pipelines would engage 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. The limited amount recorded during the quarter ended March 31, 2009 is an adjustment to a sale that was initiated before November 1, 2008.

Operating revenues for the Utility segment increased $1.8 million for the six months ended March 31, 2009 as compared with the six months ended March 31, 2008. The increase reflects a $29.3 million increase in retail sales revenues offset by a $24.3 million decrease in off-system sales revenues, which is discussed above, and a $2.8 million decrease in transportation revenues. The increase in retail sales revenues for the Utility segment was primarily due to higher residential retail sales volumes, as shown in the table above. The volume increase was primarily the result of weather that was 6.5 percent colder than the prior year in the New York jurisdiction and 5.4 percent colder than the prior year in the Pennsylvania jurisdiction. The decrease in transportation revenues is attributable to conservation efforts and the poor economy.

In the New York jurisdiction, the NYPSC issued an order providing for an annual rate increase of $1.8 million beginning December 28, 2007. As part of this rate order, a rate design change was adopted that shifts a greater amount of cost recovery into the minimum bill amount, thus spreading the recovery of such costs more evenly throughout the year. As a result of this rate order, retail and transportation revenues for the six months ended March 31, 2009 were $2.2 million lower than revenues for the six months ended March 31, 2008. There was no impact to revenues when comparing the quarters ended March 31, 2009 and March 31, 2008.

Table of Contents

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

The Utility segment s earnings for the quarter ended March 31, 2009 were $32.8 million, a decrease of $1.4 million when compared with earnings of $34.2 million for the quarter ended March 31, 2008. In the New York jurisdiction, earnings decreased $0.7 million. The major factors contributing to this decrease were regulatory true-up adjustments ($0.5 million). In the Pennsylvania jurisdiction, earnings decreased $0.7 million. The major factor for this decrease was lower usage per account ($1.7 million). The phrase usage per account refers to the average gas consumption per customer account after factoring out any impact that weather may have had on consumption. However, the impact of usage on earnings was partially offset by the positive earnings impact of colder weather ($1.3 million). The Pennsylvania jurisdiction experienced higher operating costs of $0.7 million (primarily bad debt expense due to the possible impact current economic conditions may have on customers), but lower interest expense of $0.7 million offset that earnings impact. The decrease in interest expense is primarily attributable to lower interest costs associated with deferred gas costs.

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 March 31, 2009, the WNC reduced earnings by $0.4 million as weather was colder than normal for the period. For the quarter ended March 31, 2008, the WNC preserved earnings of approximately $1.1 million as weather was warmer than normal for the period.

The Utility segment s earnings for the six months ended March 31, 2009 were $54.9 million, an increase of $0.5 million when compared with earnings of $54.4 million for the six months ended March 31, 2008. In the New York jurisdiction, earnings increased $0.6 million. The major factors contributing to this increase included a $2.6 million decrease in operating costs (primarily due to a decrease in other post-retirement benefit costs) and lower interest expense ($0.3 million). The decrease in other post-retirement benefit costs stems from the NYPSC rate order that became effective December 28, 2007 whereby the rate allowance for post-retirement benefit costs was reduced given projected reductions in the other post-retirement benefit obligation as a result of an increase in the discount rate from 5% to 6.25% during 2006. These increases to earnings were partially offset by the earnings impact of the December 28, 2007 rate order discussed above ($1.4 million) and regulatory true-up adjustments of $0.5 million. In the Pennsylvania jurisdiction, earnings decreased $0.1 million. The negative earnings impact associated with lower usage per account ($1.5 million) and higher operating costs of $1.4 million (primarily bad debt expense due to the possible impact current economic conditions may have on customers) was largely offset by the positive earnings impact of colder weather ($2.2 million) and lower interest expense ($0.8 million).

For the six months ended March 31, 2009, the WNC reduced earnings in the New York jurisdiction by $0.6 million as the weather was colder than normal. For the six months ended March 31, 2008, the WNC preserved earnings of approximately $2.1 million as the weather was warmer than normal.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended March 31,			Six Months Ended March 31,		
(Thousands)	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
Firm Transportation	$39,932	$33,002	$6,930	$73,038	$64,408	$8,630
Interruptible Transportation	1,123	1,094	29	2,227	2,085	142
	41,055	34,096	6,959	75,265	66,493	8,772
Firm Storage Service	16,767	16,935	(168)	33,452	33,556	(104)
Other	3,180	7,764	(4,584)	8,389	10,977	(2,588)

	$61,002	$58,795	$2,207	$117,106	$111,026	$6,080

Table of Contents

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

(MMcf)	Three Months Ended March 31, 2009	2008	Increase	Six Months Ended March 31, 2009	2008	Increase
Firm Transportation	133,472	121,959	11,513	244,203	214,841	29,362
Interruptible Transportation	1,256	1,221	35	3,057	2,304	753
	134,728	123,180	11,548	247,260	217,145	30,115

2009 Compared with 2008

Operating revenues for the Pipeline and Storage segment increased $2.2 million for the quarter ended March 31, 2009 as compared with the quarter ended March 31, 2008. The increase was primarily due to higher transportation revenues ($7.0 million). This increase was primarily the result of higher revenues from the Empire Connector, which was placed in service in December 2008, combined with higher reservation, commodity and surcharge, and overrun revenues associated with new contracts for transportation service. Partially offsetting this increase, efficiency gas revenues, reported as part of other revenues in the table above, decreased $4.9 million. This was primarily due to lower gas prices for the three months ended March 31, 2009 as compared to the three months ended March 31, 2008. Under Supply Corporation s tariff with shippers, Supply Corporation is allowed to retain a set percentage of shipper-supplied gas to cover compressor fuel costs and other operational purposes. To the extent that Supply Corporation does not need all of the gas to cover such operational needs, it is allowed to keep the excess gas as inventory. That inventory is later sold to customers. The excess gas that is retained as inventory represents efficiency gas revenue to Supply Corporation.

Operating revenues for the Pipeline and Storage segment for the six months ended March 31, 2009 increased $6.1 million as compared with the six months ended March 31, 2008. The increase was primarily due to an $8.8 million increase in transportation revenues, largely due to higher revenues from the Empire Connector and new contracts for transportation service. Partially offsetting this increase, efficiency gas revenues decreased $2.8 million due to lower gas prices (partially offset by higher gas volumes) during the six months ended March 31, 2009 as compared to the six months ended March 31, 2008.

The Pipeline and Storage segment s earnings for the quarter ended March 31, 2009 were $15.2 million, a decrease of $0.4 million when compared with earnings of $15.6 million for the quarter ended March 31, 2008. The earnings decrease was primarily due to lower efficiency gas revenues ($3.2 million), as discussed above. Higher depreciation expense ($1.1 million), higher interest expense ($1.3 million), and a decrease in the allowance for funds used during construction ($0.5 million) also contributed to the earnings decrease. The increase in depreciation expense can be attributed primarily to an out-of-period adjustment to correct accumulated depreciation combined with the quarter ending March 31, 2009 being the first quarter of operation for the Empire Connector. The increase in interest expense can be attributed to higher debt balances, and the decrease in the allowance for funds used during construction can be attributed to the completion of the Empire Connector in December 2008. These decreases were partially offset by the earnings impact associated with higher transportation revenues ($4.4 million), as discussed above, lower operation expenses ($0.5 million), and higher interest income ($0.2 million).

The Pipeline and Storage segment s earnings for the six months ended March 31, 2009 were $32.4 million, an increase of $4.0 million when compared with earnings of $28.4 million for the six months ended March 31, 2008. The increase in earnings is primarily due to the earnings impact associated with an increase in transportation revenues ($5.6 million), as discussed in the table above. In addition, an increase in the allowance for funds used during construction ($1.6 million), lower operating costs ($0.4 million), and higher interest income ($0.2 million) further increased earnings. The increase in allowance for funds used during construction is a result of the construction of the Empire Connector, which was completed and placed in service on December 10, 2008. Construction of the Empire

Connector began in September 2007 and was limited by winter weather so the calculated allowance for funds used during construction was relatively small during the six months ended March 31, 2008. With much more

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)
significant construction work in progress balances during the quarter ended December 31, 2008, the calculated allowance for funds used during construction was much higher. The factors contributing to the earnings increase were partially offset by a decrease in efficiency gas revenues ($1.9 million), as discussed above, higher interest expense ($1.7 million), and higher depreciation expense ($0.9 million). The increase in interest expense can be attributed to higher debt balances. The increase in depreciation expense can be attributed primarily to an out-of-period adjustment to correct accumulated depreciation combined with the quarter ending March 31, 2009 being the first quarter of operation for the Empire Connector.

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended March 31,			Six Months Ended March 31,		
(Thousands)	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
Gas (after Hedging)	$38,802	$53,645	$(14,843)	$79,895	$99,202	$(19,307)
Oil (after Hedging)	46,579	59,313	(12,734)	99,650	118,956	(19,306)
Gas Processing Plant	6,077	11,033	(4,956)	13,405	22,108	(8,703)
Other	29	(1,575)	1,604	446	(2,884)	3,330
Intrasegment Elimination [1]	(4,410)	(7,696)	3,286	(9,606)	(14,707)	5,101
	$87,077	$114,720	$(27,643)	$183,790	$222,675	$(38,885)

[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.

Production Volumes	Three Months Ended	Six Months Ended

	March 31,			March 31,		
	2009	2008	Increase (Decrease)	2009	2008	Increase (Decrease)
Gas Production *(MMcf)*						
Gulf Coast	2,065	3,022	(957)	3,811	5,849	(2,038)
West Coast	1,027	977	50	2,049	2,004	45
Appalachia	2,059	1,828	231	3,910	3,744	166
Total Production	5,151	5,827	(676)	9,770	11,597	(1,827)
Oil Production *(Mbbl)*						
Gulf Coast	166	128	38	294	285	9
West Coast	648	599	49	1,330	1,227	103
Appalachia	12	28	(16)	27	65	(38)
Total Production	826	755	71	1,651	1,577	74

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

	Three Months Ended March 31,			Six Months Ended March 31,		
	2009	2008	Decrease	2009	2008	Decrease
Average Gas Price/Mcf						
Gulf Coast	$4.61	$9.50	$(4.89)	$5.72	$8.36	$(2.64)
West Coast	$4.22	$7.93	$(3.71)	$4.62	$7.34	$(2.72)
Appalachia	$5.87	$8.90	$(3.03)	$7.13	$8.15	$(1.02)
Weighted Average	$5.03	$9.05	$(4.02)	$6.05	$8.12	$(2.07)
Weighted Average After Hedging	$7.53	$9.21	$(1.68)	$8.18	$8.55	$(0.37)
Average Oil Price/bbl						
Gulf Coast	$40.43	$99.75	$(59.32)	$47.26	$94.31	$(47.05)
West Coast	$36.60	$88.45	$(51.85)	$42.45	$85.04	$(42.59)
Appalachia	$43.55	$90.15	$(46.60)	$58.10	$86.73	$(28.63)
Weighted Average	$37.47	$90.43	$(52.96)	$43.56	$86.78	$(43.22)
Weighted Average After Hedging	$56.39	$78.54	$(22.15)	$60.36	$75.44	$(15.08)

2009 Compared with 2008

Operating revenues for the Exploration and Production segment decreased $27.6 million for the quarter ended March 31, 2009 as compared with the quarter ended March 31, 2008. Gas production revenue after hedging decreased $14.8 million. This decrease is due to a decrease in the weighted average price of gas after hedging ($1.68 per Mcf) as well as a decline in gas production of 676 MMcf. The decrease in gas production occurred primarily in this segment s Gulf Coast region (957 MMcf), which is mainly the result of lingering shut-ins caused by Hurricane Ike in September 2008. While Seneca s properties sustained only superficial damage from the hurricanes, two significant producing properties remained shut-in for most of the quarter ended March 31, 2009 due to repair work on third party pipelines and onshore processing facilities. One of the properties was back on line by March 31, 2009. The other property was brought back on line for a short period of time, but was shut-in again. It is anticipated that this production will be back on line by May 31, 2009. Offsetting this decline in production, the Appalachian region production increased as a result of additional wells drilled throughout fiscal 2008. Oil production revenue after hedging decreased $12.7 million due to a $22.15 per Bbl decrease in weighted average prices after hedging. This decrease was partly offset by an increase in production, primarily in the Gulf Coast and West Coast regions of this segment.

Operating revenues for the Exploration and Production segment decreased $38.9 million for the six months ended March 31, 2009 as compared with the six months ended March 31, 2008. Oil production revenue after hedging decreased $19.3 million due primarily to a $15.08 per Bbl decrease in weighted average prices after hedging, partially offset by an increase in production (primarily in the West Coast region). Gas production revenue after hedging decreased $19.3 million due to a decrease in gas production of 1,827 MMcf as well as a decline in the weighted average price of gas after hedging ($0.37 per Mcf). The decrease in gas production occurred primarily in the Gulf Coast region (2,038 MMcf) as a result of lingering shut-ins caused by Hurricane Ike in September 2008 as noted above.

The Exploration and Production segment s earnings for the quarter ended March 31, 2009 were $18.1 million, a decrease of $16.5 million when compared with earnings of $34.6 million for the quarter ended March 31, 2008. Lower crude oil prices, lower natural gas prices and lower natural gas production decreased earnings by $11.9 million, $5.6 million and $4.0 million, respectively, while higher crude oil production increased earnings by $3.6 million. Higher operating costs of $1.8 million and lower interest income ($1.7 million) also contributed to the decline in earnings. The increase in operating costs is primarily due to an increase in bad debt expense as a result of a customer s bankruptcy filing, the recognition of actual plugging costs in excess of amounts previously accrued, and higher personnel costs in the Appalachian region. Lower lease operating expenses of $1.6 million, lower depletion expense of $1.5 million, lower interest expense of $1.5 million and the positive earnings impact of period-to-period

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)
changes in mark-to-market adjustments on derivative financial instruments of $1.2 million somewhat offset the decline in earnings. The decrease in lease operating expenses is primarily due to a reduction in steam fuel costs in the West Coast region and a decline in well servicing workover expenses and production taxes in the Gulf Coast region. The decrease in depletion is primarily due to a lower full cost pool balance after the impairment charge taken during the quarter ended December 31, 2008 combined with a lower depletion rate that resulted from an increase in proved reserves.

The Exploration and Production segment s loss for the six months ended March 31, 2009 was $65.5 million, compared with earnings of $68.6 million for the quarter ended March 31, 2008, a decrease of $134.1 million. The decrease in earnings is primarily the result of an impairment charge of $108.2 million, as discussed above. In addition, lower crude oil prices, lower natural gas prices and lower natural gas production contributed to the decrease in earnings by $16.2 million, $2.4 million and $10.2 million, respectively, while higher crude oil production increased earnings by $3.6 million. Higher operating costs of $3.3 million and lower interest income of $3.4 million also contributed to the decrease in earnings. The increase in operating costs is primarily due to an increase in bad debt expense as a result of a customer s bankruptcy filing, the recognition of actual plugging costs in excess of amounts previously accrued, and higher personnel costs in the Appalachian region. Slightly offsetting these earnings decreases were lower interest expense ($3.0 million), lower depletion expense ($2.1 million), lower lease operating expenses ($0.3 million) and the positive earnings impact of period-to-period changes in mark-to-market adjustments on derivative financial instruments ($1.3 million). The decrease in depletion is primarily due to a lower full cost pool balance after the impairment charge taken during the quarter ended December 31, 2008 combined with a lower depletion rate that resulted from an increase in proved reserves.

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended March 31,			Six Months Ended March 31,		
(Thousands)	2009	2008	Increase (Decrease)	2009	2008	Increase
Natural Gas (after Hedging)	$163,478	$191,261	$(27,783)	$278,460	$277,996	$464
Other	67	2	65	91	(14)	105
	$163,545	$191,263	$(27,718)	$278,551	$277,982	$569

Energy Marketing Volumes

	Three Months Ended March 31,			Six Months Ended March 31,		
	2009	2008	Increase	2009	2008	Increase
Natural Gas (MMcf)	22,689	21,707	982	35,825	32,548	3,277

2009 Compared with 2008

Operating revenues for the Energy Marketing segment decreased $27.7 million for the quarter ended March 31, 2009, as compared with the quarter ended March 31, 2008. The decrease reflects a decline in gas sales revenue due to a lower average price of natural gas that was recovered through revenues, somewhat offset by an increase in volumes sold.

Operating revenues for the Energy Marketing segment increased $0.6 million for the six months ended March 31, 2009 as compared with the six months ended March 31, 2008. The increase primarily reflects an increase in volumes sold, somewhat offset by a decline in the price of natural gas.

Table of Contents

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

The volume increases for the quarter and six months ended March 31, 2009, as compared with the quarter and six months ended March 31, 2008, respectively, are largely attributable to colder weather as well as sales transactions undertaken to offset certain basis risks that the Energy Marketing segment was exposed to under certain commodity purchase contracts. These offsetting transactions had the effect of increasing revenue and volumes sold with minimal impact to earnings.

Earnings in the Energy Marketing segment decreased $0.1 million and $0.4 million, respectively, for the quarter and six months ended March 31, 2009 as compared with the quarter and six months ended March 31, 2008. These decreases are partially attributable to higher operating expenses of $0.2 million for both the quarter and six-month periods due to higher bad debt expense. Higher income tax expense also negatively impacted earnings by $0.2 million and $0.3 million, respectively, for the quarter and six months ended March 31, 2009 as compared to the quarter and six months ended March 31, 2008. The increases in operating expenses and income tax expense were somewhat offset by higher margins of $0.4 million and $0.2 million, respectively, during the quarter and six months ended March 31, 2009, primarily due to higher volumes sold.

Corporate and All Other

2009 Compared with 2008

Corporate and All Other recorded earnings of $1.8 million for the quarter ended March 31, 2009, a decrease of $3.2 million when compared with earnings of $5.0 million for the quarter ended March 31, 2008. The decrease in earnings was due to lower margins from log and lumber sales ($4.5 million), lower margins by Horizon LFG ($0.5 million), and lower interest income ($0.9 million). Also, Horizon Power recognized a gain on the sale of a turbine ($0.6 million) during the quarter ended March 31, 2008 that did not recur during the quarter ended March 31, 2009. The decreases were partially offset by lower operating expenses ($1.6 million) and lower income tax expense ($1.6 million). Operating expenses related to a proxy contest in the prior year did not recur in fiscal 2009.

For the six months ended March 31, 2009, Corporate and All Other had earnings of $2.8 million, a decrease of $4.8 million when compared with earnings of $7.6 million for the six months ended March 31, 2008. The decrease in earnings was due to lower margins from log and lumber sales ($5.8 million), lower margins by Horizon LFG ($0.9 million), lower interest income ($2.2 million), lower equity method income from Horizon Power s investments in unconsolidated subsidiaries ($0.9 million), and higher interest expense ($0.6 million). Also, as discussed above, Horizon Power recognized a $0.6 million gain during 2008 that did not recur during 2009. In addition, during the quarter ended December 31, 2008, ESNE, an unconsolidated subsidiary of Horizon Power, recorded an impairment charge of $3.6 million. Horizon Power s 50% share of the impairment was $1.8 million ($1.1 million on an after tax basis). The decreases were partially offset by lower operating expenses ($2.6 million), a gain on life insurance policies held by the Company ($2.3 million), and lower income tax expense ($2.7 million). Operating expenses related to a proxy contest in the prior year did not recur in fiscal 2009.

Interest Income

Interest income was $1.2 million lower in the quarter ended March 31, 2009 as compared to the quarter ended March 31, 2008. For the six months ended March 31, 2009, interest income decreased $2.4 million as compared with the six months ended March 31, 2008. These decreases are mainly due to lower interest rates and lower average temporary cash investment balances.

Other Income

Other income decreased $1.6 million for the quarter ended March 31, 2009 as compared with the quarter ended March 31, 2008. This decrease is attributable to a decrease in the allowance for funds used during construction of $0.5 million in the Pipeline and Storage segment associated with the Empire Connector project. In addition, as noted above, Horizon Power recognized a pre-tax gain on the sale of a turbine of $0.9 million during the quarter ended March 31, 2008 that did not recur in 2009. For the six months ended March 31, 2009, other income increased $2.5 million as compared with the six months ended March 31, 2008. This increase is attributable to an increase in the allowance for funds used during

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

construction of $1.6 million in the Pipeline and Storage segment associated with the Empire Connector project, as well as a death benefit gain on life insurance proceeds of $2.3 million recognized in the Corporate category. Offsetting these increases, as noted above, Horizon Power recognized a pre-tax gain on the sale of a turbine of $0.9 million during the quarter ended March 31, 2008 that did not recur in 2009.

Interest Expense on Long-Term Debt

Interest on long-term debt increased $1.3 million for the quarter ended March 31, 2009 as compared with the quarter ended March 31, 2008. For the six months ended March 31, 2009, interest on long-term debt increased $3.0 million as compared with the six months ended March 31, 2008. This increase can be attributed to a higher average amount of long-term debt outstanding. In April 2008, the Company issued $300 million of 6.5% senior, unsecured notes due in April 2018. This increase was partly offset by the repayment of $200 million of 6.303% medium-term notes that matured on May 27, 2008 and the repayment of $100 million of 6.0% medium-term notes that matured on March 1, 2009.

Effective Tax Rate

The effective tax rate of 27.3% for the six months ended March 31, 2009 is lower than the effective tax rate of 39.1% for the six months ended March 31, 2008 due to the reduction in pre-tax income for the six months ended March 31, 2009. The reduction in pre-tax income is a result of the impairment charge recorded during the quarter ended December 31, 2008 in the Exploration and Production segment.

CAPITAL RESOURCES AND LIQUIDITY

The Company s primary source of cash during the six-month periods ended March 31, 2009 and March 31, 2008 consisted of cash provided by operating activities. This source of cash was supplemented by issues of new shares of common stock as a result of stock option exercises. During the six months ended March 31, 2009 and March 31, 2008, the common stock used to fulfill the requirements of the Company s 401(k) plans and Direct Stock Purchase and Dividend Reinvestment Plan was obtained via open market purchases. During the quarter and six months ended March 31, 2008, the Company repurchased outstanding shares of its common stock under a share repurchase program, which is discussed below under Financing Cash Flow.

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 from period to period because of the impact of rate cases. In the Utility segment, 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 Supply Corporation s straight fixed-variable rate design.

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 balances receivable 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

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

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, no cost collars, options and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $335.8 million for the six months ended March 31, 2009, an increase of $28.9 million compared with $306.9 million provided by operating activities for the six months ended March 31, 2008. The increase is primarily due to the timing of gas cost recovery in the Utility segment for the six months ended March 31, 2009 as compared to the six months ended March 31, 2008, as well as lower working capital requirements in the Corporate category due to the timing of intercompany payments. Partially offsetting these increases were decreases in cash provided by operating activities in the Exploration and Production segment due to lower crude oil and natural gas prices and lower natural gas production, as well as a decrease in the Energy Marketing segment due to an increase in hedging collateral deposits.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company s expenditures for long-lived assets totaled $170.6 million during the six months ended March 31, 2009 and $144.7 million for the six months ended March 31, 2008. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Six Months Ended March 31, (Millions)	2009	2008	Increase (Decrease)
Utility	$25.8	$23.9	$1.9
Pipeline and Storage	27.8 (1) (2)	57.1	(29.3)
Exploration and Production	117.2 (3)	64.9	52.3
All Other	0.1	1.2	(1.1)
Eliminations	(0.3) (4)	(2.4) (5)	2.1
	$170.6	$144.7	$25.9

(1) Amount for the six months ended March 31, 2009 includes $0.9 million of accrued capital expenditures related to the Empire Connector project. This amount has been excluded from the Consolidated Statement of Cash Flows at March 31, 2009, since it represents a non-cash investing activity at that date.

(2) Amount for the six months ended March 31, 2009 excludes $16.8 million of accrued capital expenditures related to the Empire Connector project accrued at September 30, 2008 and paid during the six months ended March 31, 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 March 31, 2009.

(3) Amount for the six months ended March 31, 2009 includes $7.7 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 March 31, 2009, since it represents a non-cash investing activity at that date.

(4) 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.

(5) Represents $2.4 million of capital expenditures included in the Appalachian region of the Exploration and Production segment for the purchase of storage facilities, buildings, and base gas from Supply Corporation during the quarter ended March 31, 2008.

Table of Contents

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

Utility

The majority of the Utility capital expenditures for the six months ended March 31, 2009 and March 31, 2008 were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage capital expenditures for the six months ended March 31, 2009 and March 31, 2008 were related to the Empire Connector project, which was placed into service on December 10, 2008, as well as for additions, improvements, and replacements to this segment s transmission and gas storage systems. For all of 2009, the Company expects to spend $66.0 million on Pipeline and Storage segment capital expenditures. Previously reported 2009 capital expenditures, as disclosed in the 2008 Form 10-K, were $73.0 million.

As of March 31, 2009, the Company had incurred approximately $186.5 million in costs related to the Empire Connector project that went into service on December 10, 2008. Of this amount, $4.8 million and $21.8 million (including an accrued allowance for funds used during construction of $2.6 million) were incurred for the quarter and six months ended March 31, 2009, respectively, and $20.2 million (including an accrued allowance for funds used during construction of $0.7 million) and $45.3 million (including an accrued allowance for funds used during construction of $1.2 million) were incurred during the quarter and six months ended March 31, 2008, respectively. The Company estimates that the final cost of the Empire Connector project will be approximately $192 million.

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 is actively pursuing development of several expansion projects. The largest, Supply Corporation s Appalachian Lateral pipeline project is expected to be routed through areas in Pennsylvania where producers are actively drilling and are seeking market access for their newly discovered reserves. The Appalachian Lateral will complement Supply Corporation s original West to East (W2E) project, which was designed to transport Rockies gas supply from Clarington, Ohio to the Ellisburg/Leidy/Corning area and includes the Tuscarora-to-Corning facilities previously referred to as the Tuscarora Extension. The Appalachian Lateral will transport gas supply from Pennsylvania s producing area to the Overbeck area of Supply Corporation s existing system, where the facilities associated with the W2E project will move the gas to eastern market points, including Leidy, Pennsylvania, and to interconnections with Millennium and Empire at Corning, New York. Preliminary engineering routing analysis and the development of an updated project cost estimate have been completed. Project rate development is underway in anticipation of offering prospective shippers precedent agreements by the end of June 2009.

In addition, Supply Corporation is also working with the Appalachian producers to develop two strategic compressor horsepower expansions designed to move attached Marcellus production gas to off-system markets. The first involves new compression and approximately 3.5 miles of new pipeline to establish a delivery point from Supply Corporation s Line N to Texas Eastern at Texas Eastern s Holbrook Station in southwestern Pennsylvania. This project will allow local (Marcellus) production located in the vicinity of Line N to flow south and access Texas Eastern markets. The second expansion involves the addition of compression at Supply Corporation s existing interconnect with Tennessee Gas Pipeline at Lamont, Pennsylvania. The proliferation of Marcellus production near Supply Corporation s pipeline system in this area is the primary driver, with producers expressing interest in accessing additional downstream markets. Both of these projects have a projected in-service date of late 2010 or early 2011.

In conjunction with the Appalachian Lateral and W2E transportation projects, Supply Corporation has plans to develop new storage capacity by expansion of certain of its existing storage facilities. The expansion of these fields, which Supply Corporation is pursuing concurrently with the Appalachian Lateral/W2E transportation projects, could provide approximately 8.5 MMDth of incremental storage capacity with incremental withdrawal deliverability of up to 121 MDth of natural gas per day, with service commencing as early as 2011. Supply Corporation expects that the availability of this incremental storage capacity will complement the Appalachian Lateral/W2E pipeline transportation projects and help balance the increasing flow of Appalachian and Rockies gas supply into the western Pennsylvania area, and the growing demand for gas on the east coast.

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

The timeline associated with all of Supply Corporation s pipeline and storage projects will depend on market development. Supply Corporation has not yet filed an application with the FERC for the authority to build any of these projects.

The capital cost of the Appalachian Lateral/W2E transportation projects is estimated to be in the range of $750 million to $1 billion, and is expected to be financed by a combination of debt and equity. The estimated capital cost of the other projects is not yet complete enough to announce. As of March 31, 2009, approximately $0.9 million has been spent to study the storage expansion project, $0.3 million has been spent to study the Appalachian Lateral/W2E transportation projects, and lesser amounts have been spent on preliminary engineering for the Holbrook and Lamont projects. Costs associated with these projects have been included in preliminary survey and investigation charges and have been fully reserved for at March 31, 2009.

Exploration and Production

The Exploration and Production segment capital expenditures for the six months ended March 31, 2009 were primarily well drilling and completion expenditures and included approximately $13.3 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, $24.0 million for the West Coast region and $79.9 million for the Appalachian region. These amounts included approximately $17.8 million spent to develop proved undeveloped reserves. For all of 2009, the Company expects to spend $196 million on Exploration and Production segment capital expenditures. Previously reported 2009 capital expenditures, as disclosed in the December 31, 2008 Form 10-Q, were $244 million. Estimated capital expenditures in the Gulf Coast region will remain at the previously reported $19.0 million. Estimated capital expenditures in the West Coast region will remain at the previously reported $35.0 million. In the Appalachian region, estimated capital expenditures will decrease from the previously reported $190.0 million to $142.0 million. The main reason for the decrease is the Company s decision not to acquire two tracts from the Pennsylvania Department of Conservation and Natural Resources lease sale held in September 2008. The Company decided not to acquire these tracts due to unanticipated gas pipeline routing issues. Pipeline routes acceptable to the state were more than twice the length of what was anticipated at the time of bidding.

The Exploration and Production segment capital expenditures for the six months ended March 31, 2008 included approximately $20.0 million for the Gulf Coast region, substantially all of which was for the off-shore program in the Gulf of Mexico, $20.9 million for the West Coast region and $24.0 million for the Appalachian region. The Appalachian region capital expenditures included $2.4 million for the purchase of storage facilities, buildings, and base gas from Supply Corporation, as shown in the table on the previous page. These amounts included approximately $9.0 million spent to develop proved undeveloped reserves.

All Other

The majority of the All Other category s capital expenditures for the six months ended March 31, 2009 were for purchases of equipment for Highland s sawmill and kiln operations. The majority of the All Other category s capital expenditures for the six months ended March 31, 2008 were for construction of a lumber sorter for Highland s sawmill operations that was placed into service in October 2007 as well as for purchases of equipment for Highland s sawmill and kiln operations.

Midstream is pursuing the development of gatherings systems in Tioga County and Lycoming County in Pennsylvania. The project, called the Midstream Covington Gathering Project, is to be constructed in two phases, with the first phase anticipated to be placed in service by August 31, 2009 and the second phase anticipated to be placed in service by August 31, 2010. When complete, the project will have built approximately 30 miles of gathering system pipeline at a cost of approximately $25 million to $30 million. Phase I is estimated to cost approximately $10 million. The Company anticipates funding this project with cash from operations and/or short-term borrowings. These expenditures were not included in the estimated capital expenditures reported in the Company s 2008 Form 10-K.

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

In March 2008, Horizon Power sold a gas-powered turbine that it had planned to use in the development of a co-generation plant. Horizon Power received proceeds of $5.3 million and recorded a pre-tax gain of $0.9 million associated with the sale.

The Company continuously evaluates capital expenditures and investments in corporations, partnerships, and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, timber or natural gas storage facilities and the expansion of natural gas transmission line capacities. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company s other business segments depends, to a large degree, upon market conditions.

Financing Cash Flow

The Company did not have any outstanding short-term notes payable to banks or commercial paper at March 31, 2009. However, the Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $420.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or replaced by similar lines. The total amount available to be issued under the Company s commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million, which commitment extends through September 30, 2010.

Under the Company s committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2010. At March 31, 2009, the Company s debt to capitalization ratio (as calculated under the facility) was .38. The constraints specified in the committed credit facility would permit an additional $2.04 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.

Under the Company s existing indenture covenants, at March 31, 2009, the Company would have been permitted to issue up to a maximum of $853.0 million 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 was to experience another impairment of oil and gas properties this year, 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 10%) of the Company s long-term debt (as of March 31, 2009) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

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

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 March 31, 2009, the Company had no debt outstanding under the committed credit facility.

In April 2008, the Company issued $300.0 million of 6.50% senior, unsecured notes in a private placement exempt from registration under the Securities Act of 1933. The notes have a term of 10 years, with a maturity date in April 2018. The holders of the notes may require the Company to repurchase their notes in the event of a change in control at a price equal to 101% of the principal amount. In addition, the Company was required to either offer to exchange the notes for substantially similar notes as are registered under the Securities Act of 1933 or, in certain circumstances, register the resale of the notes. In November 2008, the Company filed a registration statement with the SEC in connection with the Company s plan to offer to exchange the notes for substantially similar registered notes. The Company used $200.0 million of the proceeds to refund $200.0 million of 6.303% medium-term notes that subsequently matured on May 27, 2008. In January 2009, the SEC declared the registration statement, as amended, effective, and the Company commenced the exchange offer. The exchange transaction closed on February 20, 2009, with the entire $300 million aggregate principal amount of the original unregistered notes exchanged for substantially similar registered notes.

In April 2009, the Company issued $250.0 million of 8.75% notes due in March 2019. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $247.8 million. The holders of the notes may require the Company to repurchase their notes in the event of a change in control at a price equal to 101% of the principal amount. The proceeds of this debt issuance were used for general corporate purposes, including to replenish cash that was used to pay the $100 million due at the maturity of the Company s 6.0% medium-term notes on March 1, 2009. After this debt issuance, the Company s embedded cost of long-term debt increased from 6.5% to 6.95%.

On December 8, 2005, the Company s Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of 8 million shares in the open market or through privately negotiated transactions. The Company repurchased 2,392,675 shares for $108.9 million during the quarter and six months ended March 31, 2008 under this program. The Company completed the repurchase of the 8 million shares during the second half of fiscal 2008. In September 2008, the Company s Board of Directors authorized the repurchase of an additional 8 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 if conditions improve. The share repurchases mentioned above were funded with cash provided by operating activities.

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 and capital 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 $29.1 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. The Company s unconsolidated subsidiaries, which are accounted for

Table of Contents

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

under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $2.5 million. The Company has guaranteed 50% or $1.3 million of these capital lease commitments.

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.

Market Risk Sensitive Instruments

Beginning in fiscal 2009, the Company adopted the provisions of SFAS 157. In accordance with the adoption of SFAS 157, the Company has identified certain inputs used to recognize fair value as Level 3 (unobservable inputs). The Level 3 derivative assets relate to natural gas and oil swap agreements used to hedge forecasted sales at specific locations (southern California and the Texas-Oklahoma border). 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 these sales locations. Given the high level of historical correlation between NYMEX prices and prices at these sales locations, the Company does not believe that the fair values recorded by the Company would be significantly different from what it expects to receive upon settlement. The fair value of the Level 3 derivative assets was reduced by $2.3 million based upon the Company s assessment of counterparty credit risk. The Company applied default probabilities to the anticipated cash flows that it was expecting from its counterparties to calculate the credit reserve. The Company incorporated hedging collateral deposits received from the counterparties in calculating the credit reserve.

The Level 3 assets amount to $79.2 million at March 31, 2009 and represent 70% of the Derivative Financial Instruments Assets or 38% of the Total Assets shown in Note 2 Fair Value Measurements at March 31, 2009.

The Company uses the natural gas and crude oil swaps to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative assets (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of SFAS 133.

The significant increase in the fair value of the Level 3 assets from October 1, 2008 to March 31, 2009, as shown in Note 2, was attributable to a significant decrease in the commodity price of natural gas and crude oil during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at March 31, 2009.

For a complete discussion of market risk sensitive instruments, refer to Market Risk Sensitive Instruments in Item 7 of the Company s 2008 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 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

On January 29, 2007, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by $52.0 million. Following standard procedure, the NYPSC suspended the proposed tariff amendments to enable its staff and intervenors to conduct a routine investigation and hold hearings. Distribution Corporation explained in the filing that its request for rate relief was necessitated by decreased revenues resulting from customer conservation efforts and increased customer uncollectibles, among other things. The rate filing also included a proposal for an efficiency and conservation initiative with a revenue decoupling mechanism designed to render the Company indifferent to throughput reductions resulting from conservation. On September 20, 2007, the NYPSC issued an order approving, with modifications, Distribution Corporation s conservation program for implementation on an accelerated basis. Associated ratemaking issues, however, were reserved for consideration in the rate.

On December 21, 2007, the NYPSC issued a rate order providing for an annual rate increase of $1.8 million, together with a monthly bill surcharge that would collect up to $10.8 million to recover expenses for implementation of the conservation program. The rate increase and bill surcharge became effective December 28, 2007. The rate order further provided for a return on equity of 9.1%. The rate order also adopted Distribution Corporation s proposed revenue decoupling mechanism. The revenue decoupling mechanism, like others, decouples revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. The Company surcharges or credits any difference from the average weather normalized usage per customer account. The surcharge or credit is calculated to recover total margin for the most recent twelve-month period ending December 31, and 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 contends that portions of the rate order should be invalidated because they fail to meet the applicable legal standard for agency decisions. Among the issues challenged by the Company are the reasonableness of the NYPSC s disallowance of expense items, including health care costs, and the methodology used for calculating rate of return, which the appeal contends understated the Company s cost of equity. The Company cannot predict the outcome of the appeal at this time.

On April 7, 2009, the Governor of the State of New York signed into law an amendment to the Public Service Law increasing the utility assessment from the current rate of 1/3 of one percent to one percent of a utility s in-state gross operating revenue, together with a temporary surcharge equal, as applied, to an additional one percent of the utility s gross operating revenue. The amendment is expected to increase the assessment charged to Distribution Corporation s New York Division, based on the most current calculation, from $2.3 million to approximately $26 million, all other things being equal. The NYPSC has opened a generic proceeding for the purpose of implementing the amended law. Implementation is expected to include a provision for recovery, through rates, of the cost of the increased assessment. At this juncture, however, the Company is unable to ascertain the outcome of the generic proceeding. If the generic proceeding is delayed or fails to provide for recovery of the increased assessment, then the Company would seek to recover the increased expense by petitioning the NYPSC for an increase in rates or such other means of recovery as is available under the law.

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

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 make a filing at the FERC, within three years after the in-service date, either justifying Empire s existing recourse rates or proposing alternative rates.

Environmental Matters

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

The Company has agreed with the NYDEC to remediate a former manufactured gas plant site located in New York. The Company has received approval from the NYDEC of a Remedial Design work plan for this site and has recorded an estimated minimum liability for remediation of this site of $16.1 million.

At March 31, 2009, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be in the range of $19.0 million to $23.2 million. The minimum estimated liability of $19.0 million, which includes the $16.1 million discussed above, has been recorded on the Consolidated Balance Sheet at March 31, 2009. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet.

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

New Accounting Pronouncements

In September 2006, the FASB issued SFAS 157. SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement 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. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. In accordance with FASB Staff Position FAS No. 157-2, on October 1, 2008, the Company adopted SFAS 157 for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. The same FASB Staff Position delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items

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

that are recognized or disclosed at fair value on a recurring basis, until the Company s first quarter of fiscal 2010. For further discussion of the impact of the adoption of SFAS 157 for financial assets and financial liabilities, refer to Part I, Item 1 at Note 2 Fair Value Measurements. The Company is currently evaluating the impact that the adoption of SFAS 157 for nonfinancial assets and nonfinancial liabilities will have on its consolidated financial statements. The Company has identified Goodwill as being the major nonfinancial asset that may be impacted by the adoption of SFAS 157. The Company does not believe there are any nonfinancial liabilities that will be impacted by the adoption of SFAS 157.

In September 2006, the FASB issued SFAS 158, an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R. SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan s assets and obligations that determine its funded status be measured as of the end of the Company s fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be fully adopted by the Company by the end of fiscal 2009. The Company has historically measured its plan assets and benefit obligations using a June 30th measurement date. In anticipation of changing to a September 30th measurement date, the Company will be recording fifteen months of pension and other post-retirement benefit costs during fiscal 2009. In accordance with the provisions of SFAS 158, these costs have been calculated using June 30, 2008 measurement date data. Three of those months pertain to the period of July 1, 2008 to September 30, 2008. The pension and other post-retirement benefit costs for that period amounted to $5.1 million and have been recorded by the Company during the quarter ended December 31, 2008 as a $3.8 million increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $1.3 million ($0.8 million after tax) adjustment to earnings reinvested in the business. For further discussion of the impact of adopting the measurement date provisions of SFAS 158, refer to Part I, Item 1 at Note 9 Retirement Plan and Other Post-Retirement Benefits.

In December 2007, the FASB issued SFAS 141R. SFAS 141R will significantly change the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under SFAS 141R, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. SFAS 141R is effective as of the Company s first quarter of fiscal 2010.

In December 2007, the FASB issued SFAS 160. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. SFAS 160 is effective as of the Company s first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued SFAS 161. SFAS 161 requires entities to provide enhanced disclosures related to an entity s derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity s financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The Company adopted the disclosure provisions of SFAS 161 during the quarter ended March 31, 2009. These disclosures may be found at Part I, Item 1 at Note 3 Derivative Financial Instruments.

On December 31, 2008, the SEC issued a final rule on Modernization of Oil and Gas Reporting. The final rule modifies the SEC s reporting and disclosure rules for oil and gas reserves and aligns the full cost accounting rules with the revised disclosures. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits

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

voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements are effective for the Company s Form 10-K for the period ended September 30, 2010. Early adoption is not permitted. The Company is currently evaluating the impact that adoption of these rules will have on its consolidated financial statements and MD&A disclosures.

In April 2009, the FASB issued FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments. This FASB Staff Position amends SFAS 107, Disclosures about Fair Value of Financial Instruments, to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. These disclosures will be required in the Company s Form 10-Q for the period ended June 30, 2009.

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, s similar expressions, are forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management s examination of historical operating trends, data contained in the Company s records and other data available from third parties, but there can 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;

Table of Contents

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

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 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;
7. Changes in demographic patterns and weather conditions;
8. 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;
9. Impairments under the SEC s full cost ceiling test for natural gas and oil reserves;
10. Uncertainty of oil and gas reserve estimates;
11. 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, and the need to obtain governmental approvals and permits and comply with environmental laws and regulations;
12. Significant differences between the Company s projected and actual production levels for natural gas or oil;
13. Changes in the availability and/or price of derivative financial instruments;
14. 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;
15. Inability to obtain new customers or retain existing ones;
16. Significant changes in competitive factors affecting the Company;
17. Changes in laws and regulations to which the Company is subject, including tax, environmental, safety and employment laws and regulations;
18. Governmental/regulatory actions, initiatives and proceedings, including those involving acquisitions, financings, rate cases (which address, among other things, allowed rates of return, rate design and retained natural gas), affiliate relationships, industry structure, franchise renewal, and environmental/safety requirements;
19. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;
20. 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;
21. The nature and projected profitability of pending and potential projects and other investments, and the ability to obtain necessary governmental approvals and permits;
22. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;
23. Significant changes in tax rates or policies or in rates of inflation or interest;

Table of Contents

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

24. Significant changes in the Company s relationship with its employees or contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur;
25. Changes in accounting principles or the application of such principles to the Company;
26. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
27. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or
28. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term disclosure controls and procedures is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company s management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company s management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company s disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company s Chief Executive Officer and Principal Financial Officer concluded that the Company s disclosure controls and procedures were effective as of March 31, 2009.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company s internal control over financial reporting that occurred during the quarter ended March 31, 2009 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

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

In addition to these matters, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of

Table of Contents

Item 1. Legal Proceedings (Concl.)

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 2008 Form 10-K, as amended by Item 1A of the Company s Form 10-Q for the quarter ended December 31, 2008, have not materially changed other than as set forth below. The risk factors presented below supersede the risk factors having the same captions in the 2008 Form 10-K and the December 31, 2008 Form 10-Q and should otherwise be read in conjunction with all of the risk factors disclosed in the 2008 Form 10-K and the December 31, 2008 Form 10-Q.

National Fuel is dependent on bank credit facilities and continued access to capital markets to successfully execute its operating strategies.

In addition to its longer term debt that is issued under its indentures, National Fuel relies upon shorter term bank borrowings and commercial paper to finance a portion of its operations. National Fuel is dependent on these capital sources to provide capital to its subsidiaries to allow them to acquire, maintain and develop their properties. The availability and cost of these credit sources is cyclical and these capital sources may not remain available to National Fuel or National Fuel may not be able to obtain money at a reasonable cost in the future. Recent access to the commercial paper markets has been on less favorable terms as a result of ongoing turmoil in the credit markets, and the commercial paper markets may not consistently be a reliable source of short-term financing for National Fuel in the future. National Fuel s ability to borrow under its credit facilities and commercial paper agreements depends on National Fuel s compliance with its obligations under the facilities and agreements. In addition, all of National Fuel s short-term bank loans are in the form of floating rate debt or debt that may have rates fixed for very short periods of time. At present, National Fuel has no active interest rate hedges in place to protect against interest rate fluctuations on short-term bank debt. In addition, the interest rates on National Fuel s short-term bank loans and the ability of National Fuel to issue commercial paper are affected by its debt credit ratings published by Standard & Poor s Ratings Service (S&P), Moody s Investors Service and Fitch Ratings Service. On February 25, 2009, S&P downgraded National Fuel s senior unsecured credit rating to BBB from BBB+ and removed the rating from CreditWatch with negative implications. In the event of any further downgrade in National Fuel s credit ratings, National Fuel s interest cost on debt issued could increase and its availability of money from banks, commercial paper purchasers and other sources could be negatively impacted. National Fuel s debt securities are currently rated at investment grade and the Company believes it is important to maintain investment grade credit ratings to conduct its business.

National Fuel s need to comply with comprehensive, complex, and sometimes unpredictable government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

While National Fuel generally refers to its Utility segment and its Pipeline and Storage segment as its regulated segments, there are many governmental regulations that have an impact on almost every aspect of National Fuel s businesses. Existing statutes and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company, which may affect its business in ways that the Company cannot predict.

On April 7, 2009, the Governor of the State of New York signed into law an amendment to the Public Service Law increasing the assessment on utility companies from the current rate of 1/3 of one percent to one percent of a utility s in-state gross operating revenue, and imposing a temporary surcharge equal, as applied, to an additional one percent of the utility s gross operating revenue. Distribution Corporation expects to be able to recover, through rates, this increase in its assessment, though there can

Item 1A. Risk Factors (Cont.)

be no assurance of recovery. The increased assessment could have a material adverse effect on the Company s results of operations, financial condition or cash flows to the extent Distribution Corporation is unable to recover it through rates.

In its Utility segment, the operations of Distribution Corporation are subject to the jurisdiction of the NYPSC and the PaPUC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Distribution Corporation is required in a rate proceeding to reduce the rates it charges its utility customers, or to the extent Distribution Corporation is unable to obtain approval for rate increases from these regulators, particularly when necessary to cover increased costs (including costs that may be incurred in connection with governmental investigations or proceedings or mandated infrastructure inspection, maintenance or replacement programs), earnings may decrease.

In addition to their historical methods of utility regulation, both the PaPUC and NYPSC have sought to establish competitive markets in which customers may purchase supplies of gas from marketers, rather than from utility companies. In June 1999, the Governor of Pennsylvania signed into law the Natural Gas Choice and Competition Act. The Act revised the Public Utility Code relating to the restructuring of the natural gas industry, to permit consumer choice of natural gas suppliers. The early programs instituted to comply with the Act did not result in significant change, and many residential customers currently continue to purchase natural gas from the utility companies. In October 2005, the PaPUC concluded that effective competition does not exist in the retail natural gas supply market statewide. On September 11, 2008, the PaPUC adopted a Final Order and Action Plan designed to increase effective competition in the retail market for natural gas services. The plan sets forth a schedule of action items for utilities and the PaPUC in order to remove barriers in the market structure that, in the opinion of the PaPUC, prevented the full participation of unregulated natural gas suppliers in Pennsylvania retail markets. In New York, in August 2004, the NYPSC issued its Statement of Policy on Further Steps Toward Competition in Retail Energy Markets. This policy statement has a similar goal of encouraging customer choice of alternative natural gas providers. In 2005, the NYPSC stepped up its efforts to encourage customer choice at the retail residential level, and customer choice activities increased in Distribution Corporation s New York service territory. In April 2007, the NYPSC, noting that the retail energy marketplace in New York is established and continuing to expand, commenced a review to determine if existing programs initially designed to promote competition had outlived their usefulness and whether the cost of programs currently funded by utility rate payers should be shifted to market competitors. Increased retail choice activities, to the extent they occur, may increase Distribution Corporation s cost of doing business, put an additional portion of its business at regulatory risk, and create uncertainty for the future, all of which may make it more difficult to manage Distribution Corporation s business profitably.

Both the NYPSC and the PaPUC have instituted proceedings for the purpose of promoting conservation of energy commodities, including natural gas. In New York, Distribution Corporation implemented a Conservation Incentive Program that promotes conservation and efficient use of natural gas by offering customer rebates for high-efficiency appliances, among other things. The intent of conservation and efficiency programs is to reduce customer usage of natural gas. Under traditional volumetric rates, reduced usage by customers results in decreased revenues to the Utility. To prevent revenue erosion caused by conservation, the NYPSC approved a revenue decoupling mechanism that renders Distribution Corporation s New York division financially indifferent to the effects of conservation. In Pennsylvania, although a proceeding is pending, the PaPUC has not yet directed Distribution Corporation to implement conservation measures. If the NYPSC were to revoke the revenue decoupling mechanism in a future proceeding or the PaPUC were to adopt a conservation program without a revenue decoupling mechanism or other changes in rate design, reduced customer usage could decrease revenues, forcing Distribution Corporation to file for rate relief.

In its Pipeline and Storage segment, National Fuel is subject to the jurisdiction of the FERC with respect to Supply Corporation and Empire. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their natural gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets

-54-

Item 1A. **Risk Factors (Concl.)**

that are dedicated to those operations. State commissions can also petition the FERC to investigate whether Supply Corporation s and Empire s rates are still just and reasonable, and if not, to reduce those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to reduce the rates it charges its natural gas transportation and/or storage customers, or if Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation s or Empire s earnings may decrease.

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

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

Environmental regulation significantly affects National Fuel s business.

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

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

On January 2, 2009, the Company issued a total of 2,100 unregistered shares of Company common stock to the seven non-employee directors of the Company then serving on the Board of Directors of the Company and receiving compensation under the Company s Retainer Policy for Non-Employee Directors, 300 shares to each such director. All of these unregistered shares were issued as partial consideration for the directors services during the quarter ended March 31, 2009. These transactions were exempt from registration by Section 4(2) of the Securities Act of 1933 as transactions not involving a public offering.

Table of Contents

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds (Concl.)
Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[a]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs [b]
Jan. 1 - 31, 2009	12,687	$ 29.03	-	6,971,019
Feb. 1 - 28, 2009	11,817	$ 32.33	-	6,971,019
Mar. 1 - 31, 2009	12,601	$ 29.03	-	6,971,019
Total	37,105	$ 30.08	-	6,971,019

(a) Represents 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. During the quarter ended March 31, 2009, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program.

(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 if conditions improve. Such repurchases would be made in the open market or through private transactions.

Item 4. Submission of Matters to a Vote of Security Holders

The Annual Meeting of Stockholders of National Fuel Gas Company was held on March 12, 2009. At that meeting, the shareholders elected directors, appointed an independent registered public accounting firm and approved the 2009 Non-Employee Director Equity Compensation Plan.

The total votes were as follows:

		For	Withheld
(i)	Election of directors to serve for a three-year term:		
	- R. Don Cash	52,378,949	16,297,197
	- Stephen E. Ewing	52,669,380	16,006,766
	- George L. Mazanec	52,542,913	16,133,233

Other directors whose term of office continued after the meeting:

Term expiring in 2010:	Philip C. Ackerman, Craig G. Matthews, Richard G. Reiten and David F. Smith.
Term expiring in 2011:	Robert T. Brady, Rolland E. Kidder and Frederic V. Salerno.

Table of Contents

Item 4. Submission of Matters to a Vote of Security Holders (Concl.)

		For	Against	Abstain	Broker Non-Votes
(ii)	Appointment of PricewaterhouseCoopers LLP as independent registered public accounting firm	67,484,057	869,658	322,431	-
(iii)	Approval of the 2009 Non-Employee Director Equity Compensation Plan	46,747,283	6,181,400	994,456	-

Item 6. Exhibits

Exhibit Number	Description of Exhibit
10.1	National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan.
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended March 31, 2009 and the Fiscal Years Ended September 30, 2005 through 2008.
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 Statement of Income for the Twelve Months Ended March 31, 2009 and 2008.

Table of Contents

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

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

Date: May 1, 2009