NATIONAL FUEL GAS CO
Form 10-Q
February 05, 2016
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended December 31, 2015
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 þ NO ¨

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

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

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

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

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

Common stock, par value $1.00 per share, outstanding at January 31, 2016: 84,790,295 shares.

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GLOSSARY OF TERMS

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

National Fuel Gas Companies	
Company	The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
Midstream Corporation	National Fuel Gas Midstream Corporation
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
Seneca	Seneca Resources Corporation
Supply Corporation	National Fuel Gas Supply Corporation
Regulatory Agencies	
CFTC	Commodity Futures Trading Commission
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
NYDEC	New York State Department of Environmental Conservation
NYPSC	State of New York Public Service Commission
PaDEP	Pennsylvania Department of Environmental Protection
PaPUC	Pennsylvania Public Utility Commission
SEC	Securities and Exchange Commission
Other	
2015 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2015
Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Bcfe (or Mcfe) – represents Bcf (or Mcf) Equivalent	The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.
Btu	British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit
Capital expenditure	Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
Cashout revenues	A cash resolution of a gas imbalance whereby a customer pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.
Degree day	A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative	A financial instrument or other contract, the terms of which include 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, forward contracts, options, no cost collars and swaps.
Development costs	Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas

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Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act.
Dth	Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act	Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets	Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploration costs	Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
FERC 7(c) application	An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.
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.
ICE	Intercontinental Exchange. An exchange which maintains a futures market for crude oil and 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.
LDC	Local distribution company
LIBOR	London Interbank Offered Rate
LIFO	Last-in, first-out
Marcellus Shale	A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.
Mbbl	Thousand barrels (of oil)
Mcf	Thousand cubic feet (of natural gas)
MD&A	Management’s Discussion and Analysis of Financial Condition and Results of Operations
MDth	Thousand decatherms (of natural gas)
MMBtu	Million British thermal units (heating value of one decatherm of natural gas)
MMcf	Million cubic feet (of natural gas)
NEPA	National Environmental Policy Act of 1969, as amended
NGA	The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
NYMEX	

	New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Open Season	A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
Precedent Agreement	An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called “conditions precedent”) happen, usually within a specified time.

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Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves	Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.
Reserves	The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Revenue decoupling mechanism	A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
S&P	Standard & Poor's Rating Service
SAR	Stock appreciation right
Service agreement	The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
Stock acquisitions	Investments in corporations
VEBA	Voluntary Employees' Beneficiary Association
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

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• The Company has nothing to report under this item.

All references to a certain year in this report are to the Company’s fiscal year ended September 30 of that year, unless otherwise noted.

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Part I. Financial Information

Item 1. Financial Statements
National Fuel Gas Company
Consolidated Statements of Income and Earnings
Reinvested in the Business
(Unaudited)

	Three Months Ended December 31,	
(Thousands of Dollars, Except Per Common Share Amounts)	2015	2014
INCOME		
Operating Revenues	$375,195	$523,909
Operating Expenses		
Purchased Gas	42,068	127,091
Operation and Maintenance	112,692	112,582
Property, Franchise and Other Taxes	20,357	20,929
Depreciation, Depletion and Amortization	70,551	102,747
Impairment of Oil and Gas Producing Properties	435,451	—
	681,119	363,349
Operating Income (Loss)	(305,924)	160,560
Other Income (Expense):		
Interest Income	1,799	1,258
Other Income	2,418	1,183
Interest Expense on Long-Term Debt	(30,372)	(22,311)
Other Interest Expense	(1,380)	(790)
Income (Loss) Before Income Taxes	(333,459)	139,900
Income Tax Expense (Benefit)	(144,350)	55,160
Net Income (Loss) Available for Common Stock	(189,109)	84,740
EARNINGS REINVESTED IN THE BUSINESS		
Balance at Beginning of Period	1,103,200	1,614,361
	914,091	1,699,101
Dividends on Common Stock	(33,472)	(32,442)
Balance at December 31	$880,619	$1,666,659
Earnings Per Common Share:		
Basic:		
Net Income (Loss) Available for Common Stock	$(2.23)	$1.01
Diluted:		
Net Income (Loss) Available for Common Stock	$(2.23)	$1.00
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	84,651,233	84,208,645
Used in Diluted Calculation	84,651,233	85,118,516
Dividends Per Common Share:		
Dividends Declared	$0.395	$0.385

See Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended December 31,	
(Thousands of Dollars)	2015	2014
Net Income (Loss) Available for Common Stock	$(189,109)	$84,740
Other Comprehensive Income (Loss), Before Tax:		
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(638)	(412)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	65,372	243,829
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(57,170)	(24,265)
Other Comprehensive Income (Loss), Before Tax	7,564	219,152
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(191)	(160)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	20,676	102,949
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(18,005)	(10,089)
Income Taxes – Net	2,480	92,700
Other Comprehensive Income	5,084	126,452
Comprehensive Income (Loss)	$(184,025)	$211,192

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2015	September 30, 2015
ASSETS		
Property, Plant and Equipment	$9,311,376	$9,261,323
Less - Accumulated Depreciation, Depletion and Amortization	4,428,593	3,929,428
	4,882,783	5,331,895
Current Assets		
Cash and Temporary Cash Investments	36,329	113,596
Hedging Collateral Deposits	9,551	11,124
Receivables – Net of Allowance for Uncollectible Accounts of $30,946 and $29,029, Respectively	211,112	105,004
Unbilled Revenue	40,178	20,746
Gas Stored Underground	28,811	34,252
Materials and Supplies - at average cost	32,389	30,414
Other Current Assets	66,145	60,665
	424,515	375,801
Other Assets		
Recoverable Future Taxes	172,205	168,214
Unamortized Debt Expense	2,085	2,218
Other Regulatory Assets	275,721	278,227
Deferred Charges	16,410	15,129
Other Investments	108,209	92,990
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	25,357	24,459
Fair Value of Derivative Financial Instruments	277,409	270,363
Other	162	167
	883,034	857,243
Total Assets	$6,190,332	$6,564,939

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2015	September 30, 2015
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 84,739,068 Shares and 84,594,383 Shares, Respectively	$84,739	$84,594
Paid in Capital	748,867	744,274
Earnings Reinvested in the Business	880,619	1,103,200
Accumulated Other Comprehensive Income	98,456	93,372
Total Comprehensive Shareholders' Equity	1,812,681	2,025,440
Long-Term Debt, Net of Unamortized Discount and Debt Issuance Costs	2,084,562	2,084,009
Total Capitalization	3,897,243	4,109,449
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	31,400	—
Current Portion of Long-Term Debt	—	—
Accounts Payable	126,917	180,388
Amounts Payable to Customers	45,076	56,778
Dividends Payable	33,472	33,415
Interest Payable on Long-Term Debt	30,285	36,200
Customer Advances	23,425	16,236
Customer Security Deposits	16,757	16,490
Other Accruals and Current Liabilities	95,830	96,557
Fair Value of Derivative Financial Instruments	7,969	10,076
	411,131	446,140
Deferred Credits		
Deferred Income Taxes	999,399	1,137,962
Taxes Refundable to Customers	94,468	89,448
Unamortized Investment Tax Credit	644	731
Cost of Removal Regulatory Liability	184,784	184,907
Other Regulatory Liabilities	113,187	108,617
Pension and Other Post-Retirement Liabilities	205,431	202,807
Asset Retirement Obligations	158,108	156,805
Other Deferred Credits	125,937	128,073
	1,881,958	2,009,350
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$6,190,332	$6,564,939

See Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended December 31,	
(Thousands of Dollars)	2015	2014
OPERATING ACTIVITIES		
Net Income (Loss) Available for Common Stock	$(189,109)	$84,740
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Impairment of Oil and Gas Producing Properties	435,451	—
Depreciation, Depletion and Amortization	70,551	102,747
Deferred Income Taxes	(140,013)	33,207
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(226)	(7,667)
Stock-Based Compensation	960	3,078
Other	3,418	2,358
Change in:		
Hedging Collateral Deposits	1,573	(10,734)
Receivables and Unbilled Revenue	(31,150)	(60,947)
Gas Stored Underground and Materials and Supplies	3,466	9,386
Other Current Assets	(5,254)	(5,635)
Accounts Payable	(20,784)	19,378
Amounts Payable to Customers	(11,702)	2,249
Customer Advances	7,189	1,431
Customer Security Deposits	267	630
Other Accruals and Current Liabilities	(14,353)	(6,416)
Other Assets	885	2,142
Other Liabilities	2,904	19,132
Net Cash Provided by Operating Activities	114,073	189,079
INVESTING ACTIVITIES		
Capital Expenditures	(186,437)	(244,927)
Net Proceeds from Sale of Oil and Gas Producing Properties	10,574	—
Other	(15,756)	(1,229)
Net Cash Used in Investing Activities	(191,619)	(246,156)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	31,400	87,300
Excess Tax Benefits Associated with Stock-Based Compensation Awards	226	7,667
Dividends Paid on Common Stock	(33,415)	(32,400)
Net Proceeds from Issuance of Common Stock	2,068	1,548
Net Cash Provided by Financing Activities	279	64,115
Net Increase (Decrease) in Cash and Temporary Cash Investments	(77,267)	7,038
Cash and Temporary Cash Investments at October 1	113,596	36,886
Cash and Temporary Cash Investments at December 31	$36,329	$43,924

Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$93,983	$101,664
Receivable from Sale of Oil and Gas Producing Properties	$94,364	$—

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Notes to Condensed Consolidated Financial Statements
(Unaudited)

Note 1 - Summary of Significant Accounting Policies

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

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

Reclassification. Due to the adoption of the authoritative guidance regarding the presentation of deferred income taxes, certain prior year amounts have been reclassified to conform with current year presentation. The Company reclassified Deferred Income Taxes of $137.2 million previously shown as Current Assets to Deferred Income Taxes shown as Deferred Credits on the Consolidated Balance Sheet at September 30, 2015.

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments (which consist of only normally recurring adjustments, unless otherwise disclosed in this Form 10-Q) 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, 2015, 2014 and 2013 that are included in the Company's 2015 Form 10-K. The consolidated financial statements for the year ended September 30, 2016 will be audited by the Company's independent registered public accounting firm after the end of the fiscal year.

The earnings for the three months ended December 31, 2015 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2016. 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.

Hedging Collateral Deposits. This is an account title for cash held in margin accounts funded by the Company to serve as collateral for hedging positions. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instruments liability or asset balances.

Gas Stored Underground. In the Utility segment, gas stored underground is carried at lower of cost or market, on a LIFO method. Gas stored underground 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 $1.0 million at December 31, 2015, is reduced to zero by September 30 of each year as the inventory is replenished.

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

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. Such costs amounted to $169.5 million and $176.3 million at December 31, 2015 and September 30, 2015, respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

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Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. The book value of the oil and gas properties exceeded the ceiling at December 31, 2015. As such, the Company recognized a pre-tax impairment charge of $435.5 million for the quarter ended December 31, 2015. A deferred income tax benefit of $182.9 million related to the impairment charge was also recognized for the quarter ended December 31, 2015. In adjusting estimated future cash flows for hedging under the ceiling test at December 31, 2015, estimated future net cash flows were increased by $253.7 million.

On December 1, 2015, Seneca and IOG - CRV Marcellus, LLC (IOG), an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC, executed a joint development agreement that allows IOG to participate in the development of certain oil and gas interests owned by Seneca in Elk, McKean and Cameron Counties, Pennsylvania. Under the terms of the agreement, Seneca and IOG will jointly participate in a program that will develop up to 80 Marcellus wells, with Seneca serving as program operator. IOG will hold an 80% working interest and is obligated to participate in the first 42 wells, and has a one-time option to participate in the remaining 38 wells that can be exercised on or before July 1, 2016. With respect to the first 42 wells, IOG has committed to fund up to $231 million to develop the joint wells. At December 31, 2015, Seneca recorded $10.6 million of cash, a $94.4 million receivable (which was received in January 2016) and a $105 million reduction of property, plant and equipment in recognition of the first installment of IOG funding that is due to Seneca for costs previously incurred to develop a portion of the first 42 wells. As the fee-owner of the property's mineral rights, Seneca retains a 7.5% royalty interest and the remaining 20% working interest (26% net revenue interest) in the first 42 wells. If IOG exercises its option to participate in the remaining 38 wells, IOG has agreed to fund up to an additional $211 million to develop such joint wells. Seneca will retain a 10% royalty and the remaining 20% working interest (28% net revenue interest) in the remaining 38 wells. Seneca's working interest under the agreement will increase to 85% after IOG achieves a 15% internal rate of return.

Accumulated Other Comprehensive Income. The components of Accumulated Other Comprehensive Income and changes for the three months ended December 31, 2015 and 2014, net of related tax effect, are as follows (amounts in parentheses indicate debits) (in thousands):

	Gains and Losses on Derivative Financial Instruments	Gains and Losses on Securities Available for Sale	Funded Status of the Pension and Other Post-Retirement Benefit Plans	Total
Three Months Ended December 31, 2015				
Balance at October 1, 2015	$157,197	$5,969	$(69,794)	$93,372
Other Comprehensive Gains and Losses Before Reclassifications	44,696	(447)	—	44,249
	(39,165)	—	—	(39,165)

Amounts Reclassified From Other Comprehensive Income				
Balance at December 31, 2015	$162,728	$5,522	$(69,794)	$98,456
Three Months Ended December 31, 2014				
Balance at October 1, 2014	$43,659	$8,382	$(56,020)	$(3,979)
Other Comprehensive Gains and Losses Before Reclassifications	140,880	(252)	—	140,628
Amounts Reclassified From Other Comprehensive Income	(14,176)	—	—	(14,176)
Balance at December 31, 2014	$170,363	$8,130	$(56,020)	$122,473

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Reclassifications Out of Accumulated Other Comprehensive Income. The details about the reclassification adjustments out of accumulated other comprehensive income for the three months ended December 31, 2015 and 2014 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Income (Loss) Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income Three Months Ended December 31, 2015	2014	Affected Line Item in the Statement Where Net Income (Loss) is Presented
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	$56,327	$20,036	Operating Revenues
Commodity Contracts	920	4,229	Purchased Gas
Foreign Currency Contracts	(77)	—	Operation and Maintenance Expense
	57,170	24,265	Total Before Income Tax
	(18,005)	(10,089)	Income Tax Expense
	$39,165	$14,176	Net of Tax

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

	At December 31, 2015	At September 30, 2015
Prepayments	$8,727	$10,743
Prepaid Property and Other Taxes	15,143	13,709
Federal Income Taxes Receivable	7,120	—
Fair Values of Firm Commitments	16,618	15,775
Regulatory Assets	18,537	20,438
	$66,145	$60,665

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

	At December 31, 2015	At September 30, 2015
Accrued Capital Expenditures	$61,362	$53,652
Regulatory Liabilities	4,695	5,346
Reserve for Gas Replacement	976	—
Federal Income Taxes Payable	—	5,686
State Income Taxes Payable	751	1,170
Other	28,046	30,703
	$95,830	$96,557

Earnings Per Common Share. Basic earnings per common share is computed by dividing income or loss 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 potentially dilutive securities the Company has outstanding are stock options, SARs, restricted stock units and performance shares. As the Company recognized a net loss for the quarter ended December 31, 2015, the aforementioned securities, amounting to 394,205 securities, were not recognized in the diluted earnings per share calculation for the quarter ended December 31, 2015. For 2014, the diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. Stock options, SARs, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 2,461 securities excluded as being antidilutive for the quarter ended December 31, 2014.

Stock-Based Compensation. The Company granted 309,996 performance shares during the quarter ended December 31, 2015. The weighted average fair value of such performance shares was $30.71 per share for the quarter ended December 31, 2015. Performance shares are an award constituting units denominated in common stock of the Company, the number of which may be adjusted over a performance cycle based upon the extent to which performance goals have been satisfied. Earned performance shares may be distributed in the form of shares of common stock of the Company, an equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company. The performance shares do not entitle the participant to receive dividends during the vesting period.

Half of the performance shares granted during the quarter ended December 31, 2015 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2015 to September 30, 2018. The performance goal over the performance cycle is the Company’s total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee (“Report Group”). Total return on capital for a given company means the average of the Report Group companies’ returns on capital for each twelve month period corresponding to each of the Company’s fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these performance shares that will vest and be paid will depend upon the Company’s performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value of these performance shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award. The other half of the performance shares granted during the quarter ended December 31, 2015 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2015 to September 30, 2018. The performance goal over the performance cycle is the Company’s three-year total shareholder return relative to the three-year total shareholder return of the other companies in the Report Group. Three-year shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company’s securities at each ex-dividend date) in the Bloomberg database. The number of these total shareholder return performance shares ("TSR performance shares") that will vest and be paid will depend upon the Company’s performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value price at the date of grant for the TSR performance shares is determined using a Monte Carlo simulation technique, which includes a reduction in value for the present value of forgone dividends over the vesting term of the award. This price is multiplied by the number of TSR performance shares awarded, the result of which is recorded as compensation expense over the vesting term of the award.

The Company granted 99,843 non-performance based restricted stock units during the quarter ended December 31, 2015. The weighted average fair value of such non-performance based restricted stock units was $35.57 per share for the quarter ended December 31, 2015. Restricted stock units represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. These non-performance based restricted stock units do not entitle the participant to receive dividends during the vesting period. The accounting for non-performance based restricted stock units is the same as the accounting for restricted share awards, except that the fair value at the date of grant of the restricted stock units must be reduced by the present value of forgone dividends over the vesting term of the award.

No stock options, SARs or restricted share awards were granted by the Company during the quarter ended December 31, 2015.

New Authoritative Accounting and Financial Reporting Guidance. In May 2014, the FASB issued authoritative guidance regarding revenue recognition. The authoritative guidance provides a single, comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The original effective date of this authoritative guidance was as of the Company's first quarter of fiscal 2018. However, the FASB has delayed the effective date of the new revenue standard by one year, and the guidance will now be effective as of the Company's first quarter of fiscal 2019. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements and disclosures.

In June 2014, the FASB issued authoritative guidance regarding accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the employee has completed the requisite service period. This authoritative guidance requires that such performance targets that affect vesting be treated as performance conditions, meaning that the performance target should not be factored in the calculation of the award at the grant date. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2017, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

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In July 2015, the FASB issued authoritative guidance simplifying inventory measurement by requiring companies to value inventory at the lower of cost and net realizable value. The authoritative guidance applies to all inventory other than inventory that is measured using last-in, first-out or the retail inventory method. The intention of this authoritative guidance is to eliminate some diversity in practice. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2018, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

In November 2015, the FASB issued authoritative guidance simplifying the presentation of deferred income taxes. The authoritative guidance requires entities with a classified balance sheet to present all deferred tax assets and liabilities as noncurrent. The Company early adopted this guidance at December 31, 2015 on a retrospective basis.

In January 2016, the FASB issued authoritative guidance regarding the recognition and measurement of financial assets and liabilities. The authoritative guidance primarily affects the accounting for equity investments, financial liabilities under the fair value option and the presentation and disclosure requirements for financial instruments. All equity investments in unconsolidated entities will be measured at fair value through earnings rather than through other comprehensive income. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2019. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

Note 2 – Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of December 31, 2015 and September 30, 2015. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over the counter swaps combines gas and oil swaps because a significant number of the counterparties enter into both gas and oil swap agreements with the Company.

Recurring Fair Value Measures	At fair value as of December 31, 2015				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[1]	Total[1]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$10,323	$—	$—	$—	$10,323
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	5,350	—	—	(5,350)	—
Over the Counter Swaps – Gas and Oil	—	284,066	—	(1,598)	282,468
Foreign Currency Contacts	—	—	—	(5,059)	(5,059)
Other Investments:					
Balanced Equity Mutual Fund	36,096	—	—	—	36,096
Fixed Income Mutual Fund	21,980	—	—	—	21,980

Common Stock – Financial Services Industry	4,179	—	—	—	4,179
Other Common Stock	494	—	—	—	494
Hedging Collateral Deposits	9,551	—	—	—	9,551
Total	$87,973	$284,066	$—	$ (12,007)	$360,032
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$11,677	$—	$—	$ (5,350)	$6,327
Over the Counter Swaps – Gas and Oil	—	3,240	—	(1,598)	1,642
Foreign Currency Contracts	—	5,059	—	(5,059)	—
Total	$11,677	$8,299	$—	$ (12,007)	$7,969
Total Net Assets/(Liabilities)	$76,296	$275,767	$—	$ —	$352,063

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Recurring Fair Value Measures	At fair value as of September 30, 2015				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[1]	Total[1]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$92,196	$—	$—	$ —	$92,196
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	6,373	—	—	(6,373)	—
Over the Counter Swaps – Gas and Oil	—	272,335	1,791	(808)	273,318
Foreign Currency Contracts	—	—	—	(2,955)	(2,955)
Other Investments:					
Balanced Equity Mutual Fund	34,884	—	—	—	34,884
Fixed Income Mutual Fund	8,004	—	—	—	8,004
Common Stock – Financial Services Industry	4,318	—	—	—	4,318
Other Common Stock	450	—	—	—	450
Hedging Collateral Deposits	11,124	—	—	—	11,124
Total	$157,349	$272,335	$1,791	$ (10,136)	$421,339
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$15,276	$—	$—	$ (6,373)	$8,903
Over the Counter Swaps – Gas and Oil	—	1,981	—	(808)	1,173
Foreign Currency Contracts	—	2,955	—	(2,955)	—
Total	$15,276	$4,936	$—	$ (10,136)	$10,076
Total Net Assets/(Liabilities)	$142,073	$267,399	$1,791	$ —	$411,263

(1) Netting Adjustments represent the impact of legally-enforceable master netting arrangements that allow the Company to net gain and loss positions held with the same counterparties. The net asset or net liability for each counterparty is recorded as an asset or liability on the Company's balance sheet.

Derivative Financial Instruments

At December 31, 2015 and September 30, 2015, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX and ICE futures contracts used in the Company's Energy Marketing segment. Hedging collateral deposits of $9.6 million at December 31, 2015 and $11.1 million at September 30, 2015, which are associated with these futures contracts, have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at December 31, 2015 and September 30, 2015 consist of natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments, the majority of the crude oil price swap agreements used in the Company's Exploration and Production segment and foreign currency contracts used in the Company's Exploration and Production segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The fair value of the Level 2 foreign currency contracts is determined using the market approach based on observable market transactions of forward Canadian currency rates. The derivative financial instruments reported in Level 3 consist of a small portion of the crude oil price swap agreements used in the Company's Exploration and Production segment at September 30, 2015 that settled prior to December 31, 2015. The fair value of the Level 3 crude oil price swap agreements was based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume).

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At December 31, 2015, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company’s (assuming the derivative is in a loss position) credit default swaps rates.

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The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the quarters ended December 31, 2015 and 2014, respectively. For the quarters ended December 31, 2015 and December 31, 2014, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the periods presented in the tables below. All settlements of the derivative financial instruments are reflected in the Gains/Losses Realized and Included in Earnings column of the tables below (amounts in parentheses indicate credits in the derivative asset/liability accounts).

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)		Total Gains/Losses			
	October 1, 2015	Gains/Losses Realized and Included in Earnings	Gains/Losses Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	December 31, 2015
Derivative Financial Instruments[2]	$1,791	$(2,002)[1]	$211	$—	$—

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2015.
[2] Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)		Total Gains/Losses			
	October 1, 2014	Gains/Losses Realized and Included in Earnings	Gains/Losses Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	December 31, 2014
Derivative Financial Instruments[2]	$1,368	$(3,855)[1]	$7,824	$—	$5,337

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2014.
[2] Derivative Financial Instruments are shown on a net basis.

Note 3 – Financial Instruments

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

	December 31, 2015		September 30, 2015	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$2,084,562	$1,970,742	$2,084,009	$2,129,558

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

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

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

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity and fixed income securities. The values of the insurance contracts amounted to $45.5 million at December 31, 2015 and $45.3 million at September 30, 2015. The fair value of the equity mutual fund was $36.1 million at December 31, 2015 and $34.9 million at September 30, 2015. The gross unrealized gain on this equity mutual fund was $6.0 million at December 31, 2015 and $6.5 million at September 30, 2015. The fair value of the fixed income mutual fund was $22.0 million at December 31, 2015 and $8.0 million at September 30, 2015. The gross unrealized loss on this fixed income mutual fund was $0.1 million at December 31, 2015. The fair value of the stock of an insurance company was $4.2 million at December 31, 2015 and $4.3 million at September 30, 2015. The gross unrealized gain on this stock was $2.5 million at December 31, 2015 and $2.6 million at September 30, 2015. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments. The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment as well as the Energy Marketing segment. 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. In addition, the Company also enters into foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. These instruments are accounted for as cash flow hedges. The Company also enters into futures contracts and swaps, which are accounted for as cash flow hedges, to manage the price risk associated with forecasted gas purchases. The Company enters into futures contracts and swaps to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in value of natural gas held in storage. These instruments are accounted for as fair value hedges. The duration of the Company’s combined cash flow and fair value commodity hedges does not typically exceed 5 years while the foreign currency forward contracts do not exceed ten years. The Exploration and Production segment holds the majority of the Company’s derivative financial instruments. The derivative financial instruments held by the Energy Marketing segment are not considered to be material to the Company.

The Company has presented its net derivative assets and liabilities as “Fair Value of Derivative Financial Instruments” on its Consolidated Balance Sheets at December 31, 2015 and September 30, 2015. Substantially all of the derivative financial instruments reported on those line items relate to commodity contracts and a small portion relates to foreign currency forward contracts.

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

As of December 31, 2015, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	159.6	Bcf (short positions)

Natural Gas	3.0	Bcf (long positions)
Crude Oil	1,815,000	Bbls (short positions)

As of December 31, 2015, the Company was hedging a total of $87.5 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts (long positions).

As of December 31, 2015, the Company had $280.4 million ($162.7 million after tax) of net hedging gains included in the accumulated other comprehensive income balance. It is expected that $189.1 million ($109.7 million after tax) of such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transaction are recorded in earnings.

Refer to Note 1, under Accumulated Other Comprehensive Income, for the after-tax gain (loss) pertaining to derivative financial instruments.

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended December 31, 2015 and 2014 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Three Months Ended December 31,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Three Months Ended December 31,		Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Three Months Ended December 31,	
	2015	2014		2015	2014		2015	2014
Commodity Contracts	$65,341	$240,023	Operating Revenue	$56,327	$20,036	Operating Revenue	$137	$1,460
Commodity Contracts	$2,213	$3,806	Purchased Gas	$920	$4,229	Not Applicable	$—	$—
Foreign Currency Contracts	$(2,182)	$—	Operation and Maintenance Expense	$(77)	$—	Not Applicable	$—	$—
Total	$65,372	$243,829		$57,170	$24,265		$137	$1,460

Fair Value Hedges

The Company utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in the value of certain natural gas held in storage. With respect to fixed price sales commitments, the Company enters into long positions to mitigate the risk of price increases for natural gas supplies that could occur after the Company enters into fixed price sales agreements with its customers. With respect to fixed price purchase commitments, the Company enters into short positions to mitigate the risk of price decreases that could occur after the Company locks into fixed price purchase deals with its suppliers. With respect to storage hedges, the Company enters into short positions to mitigate the risk of price decreases that could result in a lower of cost or market writedown of the value of natural gas in storage that is recorded in the Company’s financial statements. As of December 31, 2015, the Company’s Energy Marketing segment had fair value hedges covering approximately 16.7 Bcf (16.4 Bcf of fixed price sales commitments, 0.1 Bcf of fixed price purchase commitments and 0.2 Bcf of commitments related to the withdrawal of storage gas). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Derivatives in Fair Value Hedging Relationships	Location of Gain or (Loss) on Derivative and Hedged Item Recognized in the Consolidated Statement of Income	Amount of Gain or (Loss) on Derivative Recognized in the Consolidated Statement of Income for the	Amount of Gain or (Loss) on the Hedged Item Recognized in the Consolidated Statement of Income for the

		Three Months Ended December 31, 2015 (In Thousands)	Three Months Ended December 31, 2015 (In Thousands)
Commodity Contracts	Operating Revenues	$3,920	$(3,920)
Commodity Contracts	Purchased Gas	$(61)	$61
		$3,859	$(3,859)

Credit Risk

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly

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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 and applicable foreign currency forward contracts with sixteen counterparties of which fifteen are in a net gain position. On average, the Company had $18.4 million of credit exposure per counterparty in a gain position at December 31, 2015. The maximum credit exposure per counterparty in a gain position at December 31, 2015 was $50.4 million. The Company’s gain position on such derivative financial instruments for certain counterparties exceeded the established thresholds at which the counterparties would be required to post collateral. At December 31, 2015, collateral deposits from counterparties of $35.5 million were posted. These collateral deposits are recorded as a component of Accounts Payable on the Consolidated Balance Sheet.

As of December 31, 2015, thirteen of the sixteen counterparties to the Company’s outstanding derivative instrument contracts (specifically the over-the-counter swaps and applicable foreign currency forward contracts) had a common credit-risk related contingency feature. In the event the Company’s credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company’s credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company’s outstanding derivative instrument contracts were in a liability position (or if the liability were larger) and/or the Company’s credit rating declined, then additional hedging collateral deposits may be required. At December 31, 2015, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $179.9 million according to the Company’s internal model (discussed in Note 2 — Fair Value Measurements). For its over-the-counter swap agreements and foreign currency forward contracts, no hedging collateral deposits were required to be posted by the Company at December 31, 2015.

For its exchange traded futures contracts, the Company was required to post $9.6 million in hedging collateral deposits as of December 31, 2015. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

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

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Note 4 - Income Taxes

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

	Three Months Ended December 31, 2015	2014
Current Income Taxes		
Federal	$(8,227)	$16,528
State	3,890	5,425
Deferred Income Taxes		
Federal	(97,705)	26,193
State	(42,308)	7,014
	(144,350)	55,160
Deferred Investment Tax Credit	(87)	(104)
Total Income Taxes	$(144,437)	$55,056
Presented as Follows:		
Other Income	(87)	(104)
Income Tax Expense (Benefit)	(144,350)	55,160
Total Income Taxes	$(144,437)	$55,056

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

	Three Months Ended December 31, 2015	2014
U.S. Income (Loss) Before Income Taxes	$(333,546)	$139,796
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate of 35%	$(116,741)	$48,929
State Income Taxes (Benefit)	(24,972)	8,085
Miscellaneous	(2,724)	(1,958)
Total Income Taxes	$(144,437)	$55,056

On December 18, 2015, President Obama signed into law the Protecting Americans from Tax Hikes Act of 2015, which did not have a significant impact on total income tax expense.

Note 5 - Capitalization

Common Stock. During the three months ended December 31, 2015, the Company issued 52,000 original issue shares of common stock as a result of stock option and SARs exercises and 60,650 original issue shares of common stock for restricted stock units that vested. In addition, the Company issued 32,113 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 31,810 original issue shares of common stock for the Company’s 401(k) plans. The Company also issued 4,200 original issue shares of common stock to the non-employee directors of the Company who receive compensation under the Company’s 2009 Non-Employee Director Equity

Compensation Plan, as partial consideration for the directors' services during the three months ended December 31, 2015. Holders of stock options, SARs, restricted share awards or restricted stock units will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During the three months ended December 31, 2015, 36,088 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

Current Portion of Long-Term Debt. None of the Company's long-term debt at December 31, 2015 will mature within the following twelve-month period.

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 requirements. 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.

At December 31, 2015, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be approximately $9.6 million. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 12 years.

The Company's estimated liability for clean-up costs discussed above includes a $8.4 million estimated liability to remediate a former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. As a result of this work, the Company submitted to the NYDEC a proposal to amend the NYDEC's Record of Decision remedy for the site. In April 2013, the NYDEC approved the Company's proposed amendment. Final remedial design work for the site was completed, and active remedial work is nearing completion.

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

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

Note 7 – Business Segment Information

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

The data presented in the tables below reflect financial information for the segments and reconciliations to consolidated amounts. As stated in the 2015 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income. There have not been any changes in the basis of segmentation nor in the basis of measuring segment profit or loss from those used in the Company's 2015 Form 10-K. A listing of segment assets at December 31, 2015 and September 30, 2015 is shown in the tables below.

Quarter Ended December 31, 2015 (Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$151,965	$53,354	$125	$143,848	$24,984	$374,276	$706	$213	$375,195
Intersegment Revenues	$—	$22,183	$18,640	$3,664	$311	$44,798	$—	$(44,798)	$—
Segment Profit: Net Income (Loss)	$(237,086)	$21,276	$4,921	$18,606	$1,223	$(191,060)	$189	$1,762	$(189,109)

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(Thousands)	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Segment Assets:									
At December 31, 2015	$2,103,633	$1,597,432	$467,220	$1,930,977	$87,870	$6,187,132	$78,293	$(75,093)	$6,190,332
At September 30, 2015	$2,439,801	$1,590,525	$444,358	$1,934,730	$90,676	$6,500,090	$77,350	$(12,501)	$6,564,939

Quarter Ended December 31, 2014 (Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$204,665	$51,745	$146	$210,073	$56,166	$522,795	$884	$230	$523,909
Intersegment Revenues	$—	$21,461	$24,428	$4,534	$206	$50,629	$—	$(50,629)	$—
Segment Profit: Net Income (Loss)	$26,720	$20,778	$11,623	$22,594	$2,826	$84,541	$(6)	$205	$84,740

Note 8 – Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

	Retirement Plan		Other Post-Retirement Benefits	
Three Months Ended December 31,	2015	2014	2015	2014
Service Cost	$2,928	$3,012	$583	$673
Interest Cost	10,579	10,304	5,096	4,821
Expected Return on Plan Assets	(14,842)	(14,904)	(7,883)	(8,522)
Amortization of Prior Service Cost (Credit)	308	46	(228)	(478)
Amortization of Losses	8,062	9,032	1,382	1,037
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	1,906	1,292	4,121	4,920
Net Periodic Benefit Cost	$8,941	$8,782	$3,071	$2,451

(1) The Company's policy is to record retirement plan and other post-retirement benefit costs in the Utility segment on a volumetric basis to reflect the fact that the Utility segment experiences higher throughput of natural gas in the winter months and lower throughput of natural gas in the summer months.

Employer Contributions. During the three months ended December 31, 2015, the Company contributed $4.0 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $0.7 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2016, the Company expects its contributions to the Retirement Plan to be in the range of $1.0 million to $6.0 million. In the remainder of 2016, the Company expects to contribute approximately $2.0 million to its VEBA trusts and 401(h) accounts.

Note 9 – Regulatory Matters

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an “earnings sharing mechanism” (“ESM”). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% would be allocated to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an

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increase in Distribution Corporation’s pipeline replacement spending by $8.2 million per year of the agreement. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. A $7.5 million refund provision was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014. All significant terms of the agreement, including existing rates, continue in effect beyond September 30, 2015 until modified by the NYPSC. The agreement also states that nothing in the agreement precludes the parties from meeting to discuss extending the agreement on mutually acceptable terms, and presenting such extension to the NYPSC for approval. On May 22, 2015, Distribution Corporation filed with the NYPSC a Notice of Impending Settlement Discussions stating that settlement discussions would be scheduled in the near future, and that such discussions might include, among other things, the possible extension of the agreement on mutually acceptable terms, and on October 21, 2015, Distribution Corporation filed with the NYPSC a Supplemental Notice of Impending Settlement Discussions. In the event settlement is not reached, nothing prevents Distribution Corporation from continuing to operate under the existing agreement or from filing a rate case.

FERC Rate Proceedings

On November 13, 2015, FERC approved Supply Corporation's rate case settlement that extends Supply Corporation's current FERC-approved rate case settlement, requires a rate case filing no later than December 31, 2019 and prohibits any party from seeking to initiate a rate case proceeding before September 30, 2017. Prior to this new extension settlement, Supply Corporation had been otherwise required by its existing rate settlement to make a general rate filing no later than January 1, 2016. The new extension settlement provides, among other things, that Supply Corporation reduce its maximum reservation, capacity, demand and deliverability rates by 2% effective November 1, 2015, and further reduce those rates by an additional 2% on November 1, 2016. Pursuant to the new extension settlement, Supply Corporation also adopted a mechanism that allows it to recover, as a surcharge, certain pipeline safety and greenhouse gas costs it may incur as a result of new rules and regulations.

Empire does not have a rate case currently on file with the FERC, but by order dated January 21, 2016, the FERC began a NGA Section 5 rate review of Empire's rates. By that order, Empire is required to file a Cost and Revenue Study within 75 days (by April 5, 2016).

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

OVERVIEW

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

The Company is a diversified energy company engaged principally in the production, gathering, transportation, distribution and marketing of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current development activities are focused in the Marcellus Shale. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Marcellus Shale to markets in Canada and the eastern United States. The Company also develops and produces oil reserves, primarily in California. The Company reports financial results for five business segments.

For the quarter ended December 31, 2015, the Company recorded a loss of $189.1 million. The loss is driven largely by an impairment charge of $435.5 million ($252.6 million after-tax) recorded in the Exploration and Production segment during the quarter ended December 31, 2015. 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. Due to significant declines in crude oil and natural gas commodity prices, the book value of the Company's oil and gas properties exceeded the ceiling at December 31, 2015, resulting in the impairment charge mentioned above. Given the current commodity price environment, the Company expects to record additional significant ceiling test impairments during each of the remaining quarters of fiscal 2016. For further discussion of the ceiling test and a sensitivity analysis concerning changes in crude oil and natural gas commodity prices and their impact on the ceiling test, refer to the Critical Accounting Estimates section below. For further discussion of the Company's earnings, refer to the Results of Operations section below.

The Company continues to develop its natural gas reserves in the Marcellus Shale, a Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York. The Company controls the natural gas interests associated with approximately 785,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations.

As part of its development program for the Marcellus Shale, the Company's exploration and production subsidiary, Seneca, entered into an asset-level joint development agreement in December 2015 with IOG CRV-Marcellus, LLC (IOG), an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC. The agreement focuses on the joint development of Marcellus Shale natural gas assets located in Elk, McKean and Cameron counties in north-central Pennsylvania. Under the terms of the agreement, Seneca and IOG will jointly participate in a program that will develop up to 80 Marcellus wells, with Seneca serving as program operator. IOG will hold an 80 percent working interest and is obligated to participate in the first 42 wells, and has a one-time option to participate in the remaining 38 wells that can be exercised on or before July 1, 2016. With respect to the first 42 wells, IOG has committed to fund up to $231 million to develop the joint wells. As the fee-owner of the property's mineral rights, Seneca retains a 7.5 percent royalty interest and the remaining 20 percent working interest (26 percent net revenue interest) in the first 42 wells. If IOG exercises its option to participate in the 38 wells, IOG would fund up to an additional $211 million to develop such joint wells, and Seneca would retain a 10 percent royalty and the remaining 20 percent working interest (28 percent net revenue interest) in those wells. Seneca's working interest will increase to 85 percent after IOG achieves a 15 percent internal rate of return.

Given the current low commodity price environment and the joint development agreement discussed above, the Company has reduced its forecasted 2016 capital expenditures in the Exploration and Production segment from approximately $425 million to approximately $175 million, which is net of a $105 million reimbursement from IOG for costs Seneca previously incurred to develop a portion of the first 42 wells under the joint development agreement. The Company has also reduced forecasted 2016 capital expenditures for its Pipeline and Storage segment and Gathering segment. Capital expenditures in the Pipeline and Storage segment for 2016 are estimated to be $150 million, a decrease from the previously reported $525 million almost entirely attributable to the delay in the Northern Access 2016 project to a new in-service date of November 2017 from its originally targeted late 2016 in-service date. Capital expenditures in the Gathering segment for 2016 are estimated to be $90 million, a decrease from the previously reported $140 million. The decrease is related to fewer gathering facility requirements as a result of the decrease in capital expenditure activity for the Exploration and Production segment.

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Under the Company’s existing 1974 indenture covenants, given the significant ceiling test impairments recorded during the year ended September 30, 2015 and the quarter ended December 31, 2015, the Company is precluded from issuing additional long-term unsecured indebtedness until the second quarter of fiscal 2017. Given the current commodity price environment, the Company expects to record additional significant ceiling test impairments during each of the remaining quarters of fiscal 2016. As a result, the Company would be precluded from issuing incremental long-term debt throughout much of fiscal 2017. However, with the reduction in forecasted capital expenditures discussed above, the Company does not anticipate a need for the issuance of additional long-term debt during fiscal 2016. The Company expects to use cash from operations and, if necessary, short-term borrowings to meet its capital expenditure needs for fiscal 2016. As for fiscal 2017, the Company does not expect to issue incremental long-term debt during that period and would anticipate using cash from operations and short-term borrowings under its revolving credit facility. The Company does not have any long-term debt maturing until fiscal 2018. The 1974 indenture would not preclude the Company from issuing new long-term debt to replace maturing long-term debt.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2015 Form 10-K. There have been no material changes to that disclosure other than as set forth below. The information presented below updates and should be read in conjunction with the critical accounting estimates in that Form 10-K.

Oil and Gas Exploration and Development Costs. The Company, in its Exploration and Production segment, follows the full cost method of accounting for determining the book value of its oil and natural gas properties. In accordance with this methodology, the Company is required to perform a quarterly ceiling test. Under the ceiling test, the present value of future revenues from the Company's oil and gas reserves based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (the “ceiling”) is compared with the book value of the Company’s oil and gas properties at the balance sheet date. If the book value of the oil and gas properties exceeds the ceiling, a non-cash impairment charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. The book value of the oil and gas properties exceeded the ceiling at December 31, 2015, resulting in an impairment charge of $435.5 million ($252.6 million after-tax) for the quarter ended December 31, 2015. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended December 31, 2015, based on posted Midway Sunset prices, was $45.85 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during the twelve months ended December 31, 2015, based on the quoted Henry Hub spot price for natural gas, was $2.59 per MMBtu. (Note – because actual pricing of the Company’s various producing properties varies depending on their location and hedging, the actual prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for the twelve months ended December 31, 2015.) The following table illustrates the sensitivity of the ceiling test calculation to commodity price changes, specifically showing the additional impairment that the Company would have recorded at December 31, 2015 if natural gas prices were $0.25 per MMBtu lower than the average used at December 31, 2015, the additional impairment the Company would have recorded at December 31, 2015 if crude oil prices were $5 per Bbl lower than the average used at December 31, 2015, and the additional impairment that the Company would have recorded at December 31, 2015 if both natural gas prices and crude oil prices were $0.25 per MMBtu and $5 per Bbl lower than the average prices used at December 31, 2015 (all amounts are presented after-tax). These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation, including, among others, changes in reserve quantities and future cost estimates.

Ceiling Testing Sensitivity to Commodity Price Changes

(Millions)	$0.25/MMBtu Decrease in	$5.00/Bbl Decrease in	$0.25/MMBtu Decrease in

	Natural Gas Prices	Crude Oil Prices	Natural Gas Prices and $5.00/Bbl Decrease in Crude Oil Prices
Calculated Impairment under Sensitivity Analysis	$381.2	$293.3	$421.9
Actual Impairment Recorded at December 31, 2015	252.6	252.6	252.6
Additional Impairment	$128.6	$40.7	$169.3

Looking ahead, the first day of the month Midway Sunset price for crude oil in January 2016 was $30.98 per Bbl. The first day of the month Henry Hub spot price for natural gas in January 2016 was $2.31 per MMBtu. Given these January prices, the potential that prices could stay at this level in future months, and the expected loss of significantly higher oil and gas prices from the 12-month average that will be used in the ceiling test at March 31, 2016, June 30, 2016 and September 30, 2016, the Company expects to experience significant ceiling test impairments in each of those quarters. For a more complete discussion of

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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 2015 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company recorded a loss of $189.1 million for the quarter ended December 31, 2015 compared to earnings of $84.7 million for the quarter ended December 31, 2014. The decrease in earnings is primarily the result of a loss recognized in the Exploration and Production segment. Lower earnings in the Gathering segment, Utility segment and Energy Marketing segment also contributed to the decrease. Higher earnings in the Pipeline and Storage segment and the Corporate and All Other categories partially offset these decreases.

The Company's earnings for the quarter ended December 31, 2015 include a non-cash impairment charge of $435.5 million ($252.6 million after-tax) recorded during the quarter ended December 31, 2015 for the Exploration and Production segment's oil and gas producing properties, as discussed above. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

	Three Months Ended December 31,		
(Thousands)	2015	2014	Increase (Decrease)
Exploration and Production	$(237,086)	$26,720	$(263,806)
Pipeline and Storage	21,276	20,778	498
Gathering	4,921	11,623	(6,702)
Utility	18,606	22,594	(3,988)
Energy Marketing	1,223	2,826	(1,603)
Total Reportable Segments	(191,060)	84,541	(275,601)
All Other	189	(6)	195
Corporate	1,762	205	1,557
Total Consolidated	$(189,109)	$84,740	$(273,849)

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended December 31,		
(Thousands)	2015	2014	Increase (Decrease)
Gas (after Hedging)	$106,174	$141,657	$(35,483)
Oil (after Hedging)	44,730	60,166	(15,436)
Gas Processing Plant	636	1,058	(422)
Other	425	1,784	(1,359)
	$151,965	$204,665	$(52,700)

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Production Volumes

	Three Months Ended December 31, 2015	2014	Increase (Decrease)
Gas Production (MMcf)			
Appalachia	32,788	42,798	(10,010)
West Coast	783	773	10
Total Production	33,571	43,571	(10,000)
Oil Production (Mbbl)			
Appalachia	6	9	(3)
West Coast	742	762	(20)
Total Production	748	771	(23)

Average Prices

	Three Months Ended December 31, 2015	2014	Increase (Decrease)
Average Gas Price/Mcf			
Appalachia	$1.98	$2.95	$(0.97)
West Coast	$3.65	$5.61	$(1.96)
Weighted Average	$2.02	$3.00	$(0.98)
Weighted Average After Hedging	$3.16	$3.25	$(0.09)
Average Oil Price/Bbl			
Appalachia	$39.78	$75.56	$(35.78)
West Coast	$36.05	$66.86	$(30.81)
Weighted Average	$36.08	$66.96	$(30.88)
Weighted Average After Hedging	$59.76	$78.09	$(18.33)

2015 Compared with 2014

Operating revenues for the Exploration and Production segment decreased $52.7 million for the quarter ended December 31, 2015 as compared with the quarter ended December 31, 2014. Gas production revenue after hedging decreased $35.5 million primarily due a decrease in production due to pricing-related curtailments and a $0.09 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging decreased $15.4 million due to an $18.33 per Bbl decrease in the weighted average price of oil after hedging coupled with a slight decrease in crude oil production. Processing plant revenue decreased $0.4 million, largely due to a decrease in the price of natural gas liquids and other price and volume fluctuations. In addition, other revenue decreased $1.4 million primarily due to mark-to-market adjustments related to hedging ineffectiveness that occurred during the quarter ended December 31, 2014 that did not recur during the quarter ended December 31, 2015.

The Exploration and Production segment's loss for the quarter ended December 31, 2015 was $237.1 million, a decrease of $263.8 million when compared with earnings of $26.7 million for the quarter ended December 31, 2014. The main drivers of the decrease were the aforementioned impairment charge ($252.6 million), lower crude oil prices after hedging ($8.9 million), lower natural gas prices after hedging ($1.9 million), lower natural gas production ($21.1 million), lower crude oil production ($1.1 million), the impact of mark-to-market adjustments ($0.9 million), higher interest expense ($2.8 million), and higher operating expenses ($3.0 million). The increase in interest expense was largely due to the Exploration and Production segment's share of the Company's $450 million long-term debt issuance in June 2015. The increase in operating expenses was largely due to an

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increase in professional services associated with Marcellus Shale drilling joint development agreement with IOG in December 2015. These decreases in earnings were partially offset by the impact of lower depletion expense ($23.4 million) and lower production costs ($5.1 million). The decrease in depletion expense is primarily due to the impact of impairment charges recognized in fiscal 2015, a decrease in production due to pricing related curtailments. The decrease in production costs is primarily due to the decrease in transportation costs associated with production volumes transported by Midstream Corporation due to pricing-related curtailments.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended December 31,		
(Thousands)	2015	2014	Increase (Decrease)
Firm Transportation	$56,505	$54,193	$2,312
Interruptible Transportation	975	747	228
	57,480	54,940	2,540
Firm Storage Service	17,278	17,489	(211)
Interruptible Storage Service	50	1	49
Other	729	776	(47)
	$75,537	$73,206	$2,331

Pipeline and Storage Throughput

	Three Months Ended December 31,		
(MMcf)	2015	2014	Increase (Decrease)
Firm Transportation	175,832	186,322	(10,490)
Interruptible Transportation	5,631	2,102	3,529
	181,463	188,424	(6,961)

2015 Compared with 2014

Operating revenues for the Pipeline and Storage segment increased $2.3 million for the quarter ended December 31, 2015 as compared with the quarter ended December 31, 2014. The increase was primarily due to an increase in transportation revenues of $2.5 million. The increase in transportation revenues was largely due to demand charges for transportation service from Supply Corporation’s Westside Expansion and Modernization Project, Supply Corporation's Northern Access 2015 project, which were both fully placed in service during the first quarter of fiscal 2016 and Empire's Tuscarora Lateral Project, which was placed in service in November 2015. Partially offsetting the increase was a decline in operating revenues as a result of a 2% reduction in Supply Corporation's rates associated with the rate case settlement, which became effective November 1, 2015.

Transportation volume for the quarter ended December 31, 2015 decreased by 7.0 Bcf from the prior year’s quarter due to warmer weather. Volume fluctuations, other than those caused by the addition or deletion of contracts, generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

The Pipeline and Storage segment’s earnings for the quarter ended December 31, 2015 were $21.3 million, an increase of $0.5 million when compared with earnings of $20.8 million for the quarter ended December 31, 2014. The increase in earnings is primarily due to the earnings impact of higher transportation revenues of $1.7 million, as discussed above, combined with an increase in the allowance for funds used during construction (equity component) of $1.0 million. The increase in the allowance for funds used during construction is mainly due to capital costs incurred during the quarter ended December 31, 2015 related to various expansion projects that were under construction. These earnings increases were partially offset by an increase in depreciation expense ($0.8 million) and higher interest expense ($1.0 million). The increase in depreciation expense was attributable to projects that were placed in service within the last year. The increase in interest expense was largely due to Supply Corporation's share of the Company's $450 million long-term debt issuance in June 2015.

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Gathering

Gathering Operating Revenues

(Thousands)	Three Months Ended December 31, 2015	2014	Increase (Decrease)
Gathering	$18,640	$24,428	$(5,788)
Processing and Other Revenues	125	146	(21)
	$18,765	$24,574	$(5,809)

Gathering Volume

	Three Months Ended December 31, 2015	2014	Increase (Decrease)
Gathered Volume - (MMcf)	33,800	44,872	(11,072)

2015 Compared with 2014

Operating revenues for the Gathering segment decreased $5.8 million for the quarter ended December 31, 2015 as compared with the quarter ended December 31, 2014. This decrease was due to a decrease in gathering revenues driven by an 11.1 Bcf decrease in gathered volume. The overall decrease in gathered volume was largely due to a 12.8 Bcf decrease in gathered volume on Midstream Corporation’s Trout Run Gathering System (Trout Run), a 4.8 Bcf decrease in gathered volume on Midstream Corporation’s Covington Gathering System (Covington). Most of these decreases in gathered volume are attributable to a decrease in Seneca's Marcellus Shale production largely due to pricing related curtailments. These decreases in gathered volume were partially offset by a 6.8 Bcf increase in gathered volume on Midstream Corporation's Clermont Gathering System (Clermont). This increase in gathered volume is primarily attributable to increased usage of the Clermont Gathering System due to the completion of the Northern Access 2015 project in November and December 2015.

The Gathering segment’s earnings for the quarter ended December 31, 2015 were $4.9 million, a decrease of $6.7 million when compared with earnings of $11.6 million for the quarter ended December 31, 2014. The decrease in earnings is mainly due to the earnings impact of lower gathering revenues ($3.8 million), higher interest expense ($1.8 million) and higher depreciation expense ($1.4 million). The decrease in gathering revenues is due to the decreases in gathered volume in Trout Run, Covington and Mt. Jewett, partially offset by the increase in gathered volume in Clermont, as discussed above. The increase in interest expense is largely due to the Gathering segment's share of the Company's $450 million long-term debt issuance in June 2015 coupled with a decrease in capitalized interest, which was due to various Clermont projects being placed in service. A large increase in plant balances (largely due to various Clermont projects being placed in service) led to an increase in depreciation expense.

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Utility

Utility Operating Revenues

(Thousands)	Three Months Ended December 31, 2015	2014	Increase (Decrease)
Retail Sales Revenues:			
Residential	$98,451	$146,686	$(48,235)
Commercial	12,105	18,297	(6,192)
Industrial	490	751	(261)
	111,046	165,734	(54,688)
Transportation	33,902	39,888	(5,986)
Off-System Sales	—	5,924	(5,924)
Other	2,564	3,061	(497)
	$147,512	$214,607	$(67,095)

Utility Throughput

(MMcf)	Three Months Ended December 31, 2015	2014	Increase (Decrease)
Retail Sales:			
Residential	13,133	16,467	(3,334)
Commercial	1,827	2,284	(457)
Industrial	66	89	(23)
	15,026	18,840	(3,814)
Transportation	17,615	20,949	(3,334)
Off-System Sales	—	1,669	(1,669)
	32,641	41,458	(8,817)

Degree Days

Three Months Ended December 31,	Normal	2015	2014	Percent Colder (Warmer) Than Normal[1]	Percent Colder (Warmer) Than Prior Year[1]
Buffalo	2,253	1,677	2,136	(25.6)%	(21.5)%
Erie	2,044	1,484	1,991	(27.4)%	(25.5)%

(1) Percents compare actual 2015 degree days to normal degree days and actual 2015 degree days to actual 2014 degree days.

2015 Compared with 2014

Operating revenues for the Utility segment decreased $67.1 million for the quarter ended December 31, 2015 as compared with the quarter ended December 31, 2014. This decrease largely resulted from a $54.7 million decrease in retail gas sales revenues. In addition, there was a $5.9 million decrease in off-system sales and a $6.0 million decrease in transportation revenues. The decrease in retail gas sales revenue was largely a result of a decrease in the cost of gas sold (per Mcf) coupled with lower volumes due to warmer weather. The $6.0 million decrease in transportation revenues was primarily due to a 3.3 Bcf decrease in transportation throughput due to warmer weather. During the quarter ended December 31, 2015, the Company did not engage in off-system sales as were made in the Appalachian basin, which reduced the opportunity for off-system sales.

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The Utility segment's earnings for the quarter ended December 31, 2015 were $18.6 million, a decrease of $4.0 million when compared with earnings of $22.6 million for the quarter ended December 31, 2014. The decrease in earnings was largely attributable to the impact of warmer weather in fiscal 2016 compared to fiscal 2015 ($4.6 million) while partially offset by a decrease in operating expenses of $1.0 million. The decrease in operating expenses is largely attributable to a reduction in personnel costs.

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. For the quarters ended December 31, 2015 and December 31, 2014, the WNC increased earnings by approximately $2.0 million and $0.2 million, respectively, as the weather was warmer than normal.

Energy Marketing

Energy Marketing Operating Revenues

(Thousands)	Three Months Ended December 31, 2015	2014	Increase (Decrease)
Natural Gas (after Hedging)	$25,196	$56,330	$(31,134)
Other	99	42	57
	$25,295	$56,372	$(31,077)

Energy Marketing Volume

	Three Months Ended December 31, 2015	2014	Increase (Decrease)
Natural Gas – (MMcf)	10,098	12,589	(2,491)

2015 Compared with 2014

Operating revenues for the Energy Marketing segment decreased $31.1 million for the quarter ended December 31, 2015 as compared with the quarter ended December 31, 2014. The decrease is primarily due to a decline in gas sales revenue due to a lower average price of natural gas period over period and a decrease in volume sold to retail customers as a result of warmer weather.

The Energy Marketing segment's earnings for the quarter ended December 31, 2015 were $1.2 million, a decrease of $1.6 million when compared with earnings of $2.8 million for the quarter ended December 31, 2014. This decrease in earnings was largely attributable to lower margin of $1.7 million. The decrease in margin largely reflects lower average margins per Mcf combined with the impact on margin associated with the decrease in volume sold to retail customers due to warmer weather during the quarter ended December 31, 2015.

Corporate and All Other

2015 Compared with 2014

Corporate and All Other operations recorded earnings of $2.0 million for the quarter ended December 31, 2015, compared to earnings of $0.2 million for the quarter ended December 31, 2014. Earnings primarily increased as a result of lower income tax expense of $1.0 million and lower operating expenses of $0.4 million (mainly due to a decrease in personnel costs) for the quarter ended December 31, 2015 compared with the quarter ended December 31, 2014.

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

Interest on long-term debt increased $8.1 million for the quarter ended December 31, 2015 as compared with the quarter ended December 31, 2014. This increase is due to additional long-term debt that was issued in fiscal 2015. The Company issued $450 million of 5.20% notes in June 2015. Additionally, capitalized interest (mostly in Midstream Corporation) decreased (as a result of various projects being placed in service), which increased interest expense for the quarter ended December 31, 2015 as compared to the quarter ended December 31, 2014.

CAPITAL RESOURCES AND LIQUIDITY

The Company’s primary sources of cash during the three-month period ended December 31, 2015 consisted of cash provided by operating activities, net proceeds from short-term borrowings and proceeds from Seneca's joint development agreement with IOG. Proceeds from IOG are reflected as net proceeds from the sale of oil and gas producing properties on the Statement of Cash Flows. The Company’s primary source of cash during the three-month period ended December 31, 2014 consisted of cash provided by operating activities and net proceeds from short-term borrowings. These sources of cash were supplemented by net proceeds from the issuance of common stock for both the three months ended December 31, 2015 and December 31, 2014, including the issuance of original issue shares for the Direct Stock Purchase and Dividend Reinvestment Plan.

Operating Cash Flow

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

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

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

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

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

Net cash provided by operating activities totaled $114.1 million for the three months ended December 31, 2015, a decrease of $75.0 million compared with $189.1 million provided by operating activities for the three months ended December 31, 2014. The decrease in cash provided by operating activities reflects lower cash provided by operating activities in the Exploration and Production segment, Utility segment and Gathering segment. The decrease is partially offset by an increase in cash provided by operating activities in the Energy Marketing segment. The decrease in the Exploration and Production segment is primarily due to lower cash receipts from crude oil and natural gas production as a result of lower crude oil and natural gas prices and curtailed production. The decrease in the Utility segment is primarily due to the timing of gas cost recovery. The decrease in the Gathering segment is primarily the result of a decrease in Seneca's Marcellus Shale production, which has resulted in lower gathering revenues at the Trout Run and Covington gathering systems. The increase in the Energy Marketing segment is primarily due to hedging collateral account fluctuations.

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Investing Cash Flow

Expenditures for Long-Lived Assets

The Company’s expenditures for long-lived assets totaled $161.5 million during the three months ended December 31, 2015 and $210.0 million for the three months ended December 31, 2014. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Three Months Ended December 31, (Millions)	2015		2014		Increase(Decrease)
Exploration and Production:					
Capital Expenditures	$88.1	(1)	$157.7	(2)	$ (69.6)
Pipeline and Storage:					
Capital Expenditures	31.6	(1)	16.0	(2)	15.6
Gathering:					
Capital Expenditures	21.8	(1)	15.0	(2)	6.8
Utility:					
Capital Expenditures	19.9	(1)	21.2	(2)	(1.3)
All Other:					
Capital Expenditures	0.1	(1)	0.1	(2)	—
	$161.5		$210.0		$ (48.5)

(1) At December 31, 2015, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $43.7 million, $19.0 million, $18.8 million and $12.5 million, respectively, of non-cash capital expenditures. At September 30, 2015, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $46.2 million, $33.9 million, $22.4 million and $16.5 million, respectively, of non-cash capital expenditures.

(2) At December 31, 2014, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $82.3 million, $3.0 million, $11.0 million and $5.4 million, respectively, of non-cash capital expenditures. At September 30, 2014, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $80.1 million, $28.1 million, $20.1 million and $8.3 million, respectively, of non-cash capital expenditures.

Exploration and Production

The Exploration and Production segment capital expenditures for the three months ended December 31, 2015 were primarily well drilling and completion expenditures and included approximately $80.8 million for the Appalachian region (including $75.9 million in the Marcellus Shale area) and $7.3 million for the West Coast region. These amounts included approximately $38.9 million spent to develop proved undeveloped reserves.

On December 1, 2015, Seneca and IOG - CRV Marcellus, LLC (IOG), an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC, executed a joint development agreement that allows IOG to participate in the development of certain oil and gas interests owned by Seneca in Elk, McKean and Cameron Counties, Pennsylvania. Under the terms of the agreement, Seneca and IOG will jointly participate in a program that will develop up to 80 Marcellus wells, with Seneca serving as program operator. At December 31, 2015, Seneca had received cash of $10.6 million from IOG and recorded a $94.4 million receivable (which was received in January

2016) and a $105 million reduction of property, plant and equipment in recognition of the first installment of IOG funding that is due to Seneca for costs previously incurred to develop a portion of the wells. For further discussion of the joint development agreement, refer to Item 1 at Note 1 - Summary of Significant Accounting Policies under the heading “Property, Plant and Equipment.”

The Exploration and Production segment capital expenditures for the three months ended December 31, 2014 were primarily well drilling and completion expenditures and included approximately $134.1 million for the Appalachian region (including $125.8 million in the Marcellus Shale area) and $23.6 million for the West Coast region. These amounts included approximately $60.4 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the three months ended December 31, 2015 were mainly for expenditures related to Supply Corporation's Westside Expansion and Modernization Project ($5.7 million), Supply Corporation's

Northern Access 2015 Project ($5.1 million), Supply Corporation's Northern Access 2016 Project ($8.5 million) and Empire and Supply Corporation's Tuscarora Lateral Project ($2.3 million). In addition, the Pipeline and Storage segment capital expenditures for the three months ended December 31, 2015 also include additions, improvements and replacements to this segment’s transmission and gas storage systems. The majority of the Pipeline and Storage capital expenditures for the three months ended December 31, 2014 were mainly for expenditures related to Supply Corporation's Westside Expansion and Modernization Project ($6.2 million), Supply Corporation's Mercer Expansion Project ($2.6 million) and Empire and Supply Corporation's Tuscarora Lateral Project ($1.1 million) and also included additions, improvements, and replacements to this segment’s transmission and gas storage systems.

In light of the continuing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus and Utica Shale producing areas — Supply Corporation and Empire are actively pursuing several expansion projects and paying for preliminary survey and investigation costs, which are initially recorded as Deferred Charges on the Consolidated Balance Sheet. An offsetting reserve is established as those preliminary survey and investigation costs are incurred, which reduces the Deferred Charges balance and increases Operation and Maintenance Expense on the Consolidated Statement of Income. The Company reviews all projects on a quarterly basis, and if it is determined that it is highly probable that the project will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. After the reversal of the reserve, the amounts remain in Deferred Charges until such time as capital expenditures for the project have been incurred and activities that are necessary to get the construction project ready for its intended use are in progress. At that point, the balance is transferred from Deferred Charges to Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet. As of December 31, 2015, the total amount reserved for the Pipeline and Storage segment’s preliminary survey and investigation costs was $7.9 million.

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

On January 18, 2013, Supply Corporation concluded an Open Season to further increase its capacity to move gas north and south on its Line N system to Texas Eastern Transmission, LP (“TETCO”) at Holbrook and Tennessee Gas Pipeline ("TGP") at Mercer (“Westside Expansion and Modernization Project”). Supply Corporation received its FERC 7(c) certificate on March 2, 2015 and executed two service agreements with Range Resources (Range) and Seneca for all 175,000 Dth per day of project capacity. Partial service for Range began on September 8, 2015 with full service on October 16, 2015 and for Seneca on November 1, 2015. The Westside Expansion and Modernization Project facilities include the replacement of approximately 23.3 miles of 20” pipe with 24” pipe and the addition of 3,550 horsepower of compression at Mercer. The cost estimate is $84.4 million, of which $44.1 million is related to expansion and the remainder is for replacement. As of December 31, 2015, approximately $73.6 million has been spent on the Westside Expansion and Modernization Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2015.

Supply Corporation and TGP jointly developed a project that combines expansions on both pipeline systems, providing a seamless transportation path from TGP’s 300 Line in the Marcellus fairway to the TransCanada Pipeline delivery point at Niagara. Supply Corporation offered 140,000 Dth per day of capacity on its system to TGP under a lease, from its Ellisburg Station for redelivery to TGP in East Eden, New York (“Northern Access 2015”). The project provides Seneca, TGP’s anchor shipper, with an outlet to Dawn-indexed markets in Canada, for Marcellus production from Seneca's Western Development Area at Clermont. The Northern Access 2015 project involved the construction of a new 15,400 horsepower compressor station in Hinsdale, New York and a 7,700 horsepower addition to its compressor station in Concord, New York, for service that commenced on an interim basis for 40,000 Dth per day on November 1, 2015, and was fully operational on December 1, 2015. Supply Corporation and TGP received their FERC 7(c) certificates on February 27, 2015 and executed the Capacity Lease agreement. The cost estimate for the Northern Access 2015 project is $68.3 million. As of December 31, 2015, approximately $56.6 million has been spent on the Northern Access 2015 project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2015.

Supply Corporation and Empire have been working with Seneca to develop a project which would move significant prospective Marcellus production from Seneca's Western Development Area at Clermont to an Empire interconnection with TransCanada Pipeline at Chippawa ("Northern Access 2016") and an interconnection with TGP's 200 Line in East Aurora, New York. Similar to the goal of the Northern Access 2015 project, the separate and distinct Northern Access 2016 project would provide an outlet to Dawn-indexed markets in Canada and to the TGP line serving the U.S. Northeast. The Northern Access 2016 project involves the construction of approximately 98.5 miles of largely 24" pipeline and approximately 27,500 horsepower of compression on the two systems. As a result of Seneca's slowed drilling activity and other considerations, the Company has revised the target in-service date for this project to November 1, 2017 (from the originally scheduled late calendar 2016). The revised project timeline allows the Company additional time to complete all development activities and prepare for efficient construction of the project facilities. The preliminary cost estimate for the Northern Access 2016 project is $455 million. Supply Corporation, Empire and Seneca executed anchor shipper agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa and 140,000 Dth per day of firm transportation capacity to a new interconnection with TGP's 200 Line on this project. On July 24, 2014, Supply Corporation and Empire initiated the FERC NEPA Pre-filing process on this project and both parties filed a joint FERC 7(b) and 7(c) application in early March 2015 and amended that application on November 2, 2015. As of December 31, 2015, approximately $25.6 million has been spent on the Northern Access 2016 project, including $11.2 million that has been spent to study the project. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and this $11.2 million of project costs has been reestablished as a Deferred Charge on the Consolidated Balance Sheet. The remaining $14.4 million spent on the project has been capitalized as Construction Work in Progress.

On November 21, 2014, Supply Corporation concluded an Open Season for an expansion of its Line D pipeline (“Line D Expansion”) that is intended to allow growing on-system markets to avail themselves of economical gas supply on the TGP 300 line, at an existing interconnect at Lamont, Pennsylvania, and provide increased capacity into the Erie, Pennsylvania market area. Following negotiations with prospective shippers, Supply Corporation executed five precedent agreements for a total of 77,500 Dth per day for terms of ten years. The project involves construction of a new 4,152 horsepower Keelor Compressor Station and modifications to the Roystone and Bowen compressor stations at an estimated capital cost of approximately $27.9 million. The project will also provide system modernization benefits. Supply Corporation filed on December 22, 2015 for authorization to construct this project under its FERC blanket certificate. The target in-service date is November 1, 2016. As of December 31, 2015, approximately $0.3 million has been capitalized as Construction Work in Progress for the Line D Expansion project.

On August 12, 2013, Empire concluded an Open Season, offering for the first time no-notice transportation and storage services to new and existing shippers on the Empire pipeline system. Empire and Rochester Gas & Electric (“RG&E”), Empire’s largest LDC connected market, executed a precedent agreement to convert all 172,500 Dth per day of its standard firm transportation services to no-notice service, including 3.3 Bcf of no-notice storage service. The new service provides RG&E with a superior flexible delivery service with daily and seasonal load balancing capabilities and greater access to Marcellus supplies. In addition, Empire executed a precedent agreement with New York State Electric and Gas for 14,816 Dth per day of transportation capacity and a third agreement with Distribution Corporation for the remaining 34,500 Dth per day of project capacity, providing both LDCs with increased access to Marcellus supplies. Supply Corporation concluded an Open Season and awarded to Empire the necessary storage services under a lease agreement. Empire and Supply Corporation began the FERC pre-filing process on April 12, 2013, and both companies filed their FERC 7(c) applications in March 2014. Empire and Supply Corporation received a FERC certificate on March 10, 2015. Both parties then executed the Capacity Lease, and Empire executed service agreements with all three of its project shippers. Empire constructed a 17.2 mile (12" and 16") pipeline and an interconnection between Empire's pipeline system and Supply Corporation's pipeline system at Tuscarora, New York. Empire also modified its Oakfield compressor station and Supply Corporation constructed approximately 1,380 horsepower of compression at its Tuscarora compressor station ("Tuscarora Lateral Project"), and service began November 1, 2015. The cost estimate for the Tuscarora Lateral Project is $63.0 million. As of December 31, 2015, approximately $57.8 million has been spent on the Tuscarora Lateral Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2015.

Empire is developing an expansion of its system, and concluded an Open Season on November 18, 2015, that would allow for the transportation of approximately 300,000 Dth per day of additional Marcellus supplies from Millennium Pipeline at Corning, from Supply Corporation at Tuscarora, or from new interconnections in Tioga County, Pennsylvania, to the TransCanada Pipeline and the TGP 200 Line (“Empire North Project”). The preliminary cost estimate for the Empire North Project is approximately $185 million dependent on final receipt and delivery point selections. As of December 31, 2015, approximately $0.3 million has been spent to study this project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2015.

Gathering

The majority of the Gathering segment capital expenditures for the three months ended December 31, 2015 and December 31, 2014 were for the construction of Midstream Corporation’s Clermont Gathering System, as discussed below.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Corporation, is building an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The total cost estimate for the continued buildout will be dependent on the nature and timing of Seneca's long-term plans. As of December 31, 2015, approximately $234.7 million has been spent on the Clermont Gathering System, including approximately $18.3 million spent during the three months ended December 31, 2015, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2015.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, continues to develop its Trout Run Gathering System in Lycoming County, Pennsylvania. The Trout Run Gathering System was initially placed in service in May 2012. The current system consists of approximately 42 miles of backbone and in-field gathering pipelines and two compressor stations. As of December 31, 2015, the Company has spent approximately $165.7 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2015.

Utility

The majority of the Utility segment capital expenditures for the three months ended December 31, 2015 and December 31, 2014 were made for replacement of mains and main extensions, as well as for the replacement of service lines. The capital expenditures for the three months ended December 31, 2015 and December 31, 2014 also include $2.0 million and $4.1 million, respectively, related to the replacement of the Utility segment's customer information system, which is scheduled to be placed in service in the spring of 2016.

Project Funding

The Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. Going forward, while the Company expects to use cash on hand and cash from operations as the first means of financing these projects, the Company may issue short-term debt as necessary during fiscal 2016 to help meet its capital expenditures needs. The level of short-term borrowings will depend upon the amounts of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells. As disclosed above, the Company is currently precluded from issuing new long-term debt until the second quarter of fiscal 2017 as a means of financing projects. Given the current commodity price environment, the Company expects to record additional significant ceiling test impairments during each of the remaining quarters of fiscal 2016. This would preclude the Company from issuing incremental long-term debt throughout much of fiscal 2017. However, the Company does not anticipate a need for the issuance of additional long-term debt during either fiscal 2016 or fiscal 2017.

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

Financing Cash Flow

Consolidated short-term debt increased $31.4 million when comparing the balance sheet at December 31, 2015 to the balance sheet at September 30, 2015. The maximum amount of short-term debt outstanding during the three months ended December 31, 2015 was $62.4 million. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, other working capital needs and repayment of long-term debt.

Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At December 31, 2015, the Company had $31.4 million of outstanding commercial paper and did not have any short-term notes payable to banks.
On December 5, 2014, the Company entered into an Amended and Restated Credit Agreement with a syndicate of 14 banks. The agreement replaced the Company's previous $750.0 million committed credit facility with a substantially similar facility totaling $750.0 million. On September 30, 2015, the Company entered into a Second Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of the same 14 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through December 5, 2019, plus a $500.0 million 364-day unsecured committed revolving credit facility through September 29, 2016. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines.

The total amount available to be issued under the Company's commercial paper program is $500.0 million. The commercial paper program is backed by the Credit Agreement, which provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through December 5, 2019. At December 31, 2015, the Company's debt to capitalization ratio (as calculated under the facility) was .54. The constraints specified in the Credit Agreement would have permitted an additional $1.25 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.
A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources, including cash provided by operations.
The Credit Agreement 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 Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of December 31, 2015, the Company did not have any debt outstanding under the Credit Agreement.
None of the Company's long-term debt at December 31, 2015 and 2014 had a maturity date within the following twelve-month period.

The Company's embedded cost of long-term debt was 5.53% and 5.61% at December 31, 2015 and December 31, 2014, respectively.

Under the Company's existing indenture covenants, at December 31, 2015, the Company is precluded from issuing additional long-term unsecured indebtedness until the second quarter of fiscal 2017 as a result of impairments of its oil and gas properties recognized during the year ended September 30, 2015 and the quarter ended December 31, 2015, as discussed above. The 1974 indenture would not preclude the Company from issuing new indebtedness to replace maturing debt. If the Company experiences additional significant impairments of its oil and gas properties in the second, third and fourth quarters of fiscal 2016, the Company, under its 1974 indenture, expects to continue to be precluded from issuing incremental long-term debt throughout much of fiscal 2017. However, the Company expects that it could borrow under its credit facilities. The Company's present liquidity position is believed to be adequate to satisfy known demands. Please refer to the Critical Accounting Estimates section above for a sensitivity analysis concerning commodity price changes and their impact on the ceiling test.
The Company's 1974 indenture pursuant to which $99.0 million (or 4.7%) of the Company's long-term debt (as of December 31, 2015) 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.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company's consolidated subsidiaries have operating leases, the majority of which are with the Exploration and Production segment and Corporate operations, having a remaining lease commitment of approximately $36.1 million. These leases have been entered into for the use of compressors, drilling rigs, buildings, meters and other items and are accounted for as operating leases.

OTHER MATTERS

In addition to the legal proceedings disclosed in Part II, Item 1 of this report, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

During the three months ended December 31, 2015, the Company contributed $4.0 million to its Retirement Plan and $0.7 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2016, the Company expects its contributions to the Retirement Plan to be in the range of $1.0 million to $6.0 million. In the remainder of 2016, the Company expects to contribute $2.0 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as “swap dealers” and “major swap participants,” (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC’s enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, the CFTC has imposed numerous registration, swaps documentation, business conduct, reporting, and recordkeeping requirements on swap dealers and major swap participants, which frequently are counterparties to the Company’s derivative hedging transactions. Regardless of the final capital and margin rules, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from the final and proposed rules through higher transaction costs and prices or other direct or indirect costs. In addition, while the Company expects to be exempt from the Dodd-Frank Act’s requirement that certain swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, documentation, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company’s ability to monetize or restructure existing derivative contracts; and increase the Company’s exposure to less creditworthy counterparties, all of which could increase the Company’s business costs. The Company continues to monitor these developments but cannot predict the impact the Dodd-Frank Act may ultimately have on its operations.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At December 31, 2015, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company’s (assuming the derivative is in a loss position) credit default swaps rates.

For a complete discussion of market risk sensitive instruments, refer to "Market Risk Sensitive Instruments" in Item 7 of the Company's 2015 Form 10-K. There have been no subsequent material changes to the Company’s exposure to market risk sensitive instruments.

Rate and Regulatory Matters

Utility Operation

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

New York Jurisdiction

Customer delivery rates charged by Distribution Corporation's New York division were established in a rate order issued on December 21, 2007 by the NYPSC. In connection with an efficiency and conservation program, the rate order approved a

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revenue decoupling mechanism. The revenue decoupling mechanism “decouples” revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation.

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an “earnings sharing mechanism” (“ESM”). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation’s pipeline replacement spending by $8.2 million per year of the agreement. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. A $7.5 million ($4.9 million after-tax) refund provision was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014. All significant terms of the agreement, including existing rates, continue in effect beyond September 30, 2015 until modified by the NYPSC. The agreement also states that nothing in the agreement precludes the parties from meeting to discuss extending the agreement on mutually acceptable terms, and presenting such extension to the NYPSC for approval. On May 22, 2015, Distribution Corporation filed with the NYPSC a Notice of Impending Settlement Discussions stating that settlement discussions would be scheduled in the near future, and that such discussions might include, among other things, the possible extension of the agreement on mutually acceptable terms, and on October 21, 2015, Distribution Corporation filed with the NYPSC a Supplemental Notice of Impending Settlement Discussions. In the event settlement is not reached, nothing prevents Distribution Corporation from continuing to operate under the existing agreement or from filing a rate case.

Pennsylvania Jurisdiction

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

Pipeline and Storage

On November 13, 2015, FERC approved Supply Corporation's rate case settlement that extends Supply Corporation's current FERC-approved rate case settlement, requires a rate case filing no later than December 31, 2019 and prohibits any party from seeking to initiate a rate case proceeding before September 30, 2017. Prior to this new extension settlement, Supply Corporation had been otherwise required by its existing rate settlement to make a general rate filing no later than January 1, 2016. The new extension settlement provides, among other things, that Supply Corporation reduce its maximum reservation, capacity, demand and deliverability rates by 2% effective November 1, 2015, and further reduce those rates by an additional 2% on November 1, 2016. Pursuant to the new extension settlement, Supply Corporation also adopted a mechanism that allows it to recover, as a surcharge, certain pipeline safety and greenhouse gas costs it may incur as a result of new rules and regulations.

Empire does not have a rate case currently on file with the FERC, but by order dated January 21, 2016, the FERC began a NGA Section 5 rate review of Empire's rates. By that order, Empire is required to file a Cost and Revenue Study within 75 days (by April 5, 2016).

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 requirements.
For further discussion of the Company's environmental exposures, refer to Item 1 at Note 6 — Commitments and Contingencies under the heading “Environmental Matters.”

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. In the United States, these efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation related to greenhouse gas emissions. While the U.S. Congress has from time to time considered legislation aimed at reducing emissions of greenhouse gases, Congress has not yet passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating greenhouse gas emissions pursuant to the authority granted to it by the federal Clean Air Act. For example, in April 2012, the EPA adopted rules which restrict emissions associated with oil and natural gas drilling. In 2015, the EPA proposed new rules regulating methane and volatile organic compound emissions from new or modified oil and gas emissions sources. If adopted as proposed, these new rules would impose more stringent leak detection and repair requirements, and would further address reporting and control of methane and volatile organic compound emissions. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. The Company currently complies with California cap-and-trade guidelines, which increases the Company's cost of environmental compliance in its Exploration and Production segment operations. Legislation or regulation that restricts carbon emissions could increase the Company’s cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

New Authoritative Accounting and Financial Reporting Guidance

For discussion of the recently issued authoritative accounting and financial reporting guidance, refer to Item 1 at Note 1 — Summary of Significant Accounting Policies under the heading “New Authoritative Accounting and Financial Reporting Guidance.”

Safe Harbor for Forward-Looking Statements

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

1. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
2. Changes in the price of natural gas or oil;
3. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions;
4. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;
5. Factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and

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transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;

6. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;
7. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;
8. Changes in price differential between similar quantities of natural gas or oil at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations;
9. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;
10. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
11. Uncertainty of oil and gas reserve estimates;
12. Significant differences between the Company’s projected and actual production levels for natural gas or oil;
13. Changes in demographic patterns and weather conditions;
14. Changes in the availability, price or accounting treatment of derivative financial instruments;
15. 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;
16. The creditworthiness or performance of the Company’s key suppliers, customers and counterparties;
17. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;
18. Significant differences between the Company’s projected and actual capital expenditures and operating expenses;
19. Changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company’s pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;
20. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or
21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

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Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company’s management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2015.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company’s internal control over financial reporting that occurred during the quarter ended December 31, 2015 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.”

For a discussion of certain rate matters involving the NYPSC, refer to Part I, Item 1 of this report at Note 9 — Regulatory Matters.

Item 1A. Risk Factors

The risk factors in Item 1A of the Company’s 2015 Form 10-K 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 2015 Form 10-K and should otherwise be read in conjunction with all of the risk factors disclosed in the 2015 Form 10-K.

The Company is dependent on capital and credit markets to successfully execute its business strategies.

The Company relies upon short-term bank borrowings, commercial paper markets and longer-term capital markets to finance capital requirements not satisfied by cash flow from operations. The Company is dependent on these capital sources to provide capital to its subsidiaries to fund operations, acquire, maintain and develop properties, and execute growth strategies. The availability and cost of credit sources may be cyclical and these capital sources may not remain available to the Company. Turmoil in credit markets may make it difficult for the Company to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance maturing debt on favorable terms. These difficulties could adversely affect the Company's growth strategies, operations and financial performance. The Company's ability to borrow under its credit facilities and commercial paper agreements, and its ability to issue long-term debt under its indentures, depend on the Company's compliance with its obligations under the facilities, agreements and indentures. Under the Company’s 1974 indenture, the Company has been precluded since October 1, 2015 from issuing incremental long-term debt as a result of impairments (i.e., write-downs) of its oil and gas properties. Given the impairments recognized through December 31, 2015, the Company expects to be precluded from issuing incremental long-term debt through December 2016, absent amendment or waiver by existing noteholders of a covenant in the 1974 indenture. Additionally, the Company expects to record additional significant impairments of its oil and gas properties in the second, third and fourth quarters of fiscal 2016, which would preclude the Company from issuing incremental long-term debt throughout much of fiscal 2017. The 1974 indenture would not preclude the Company from issuing new long-term debt to replace maturing long-term debt.

In addition, the Company'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, resulting in exposure to interest rate fluctuations in the absence of interest rate hedging transactions. The cost of long-term debt, the interest rates on the Company's short-term bank loans and the ability of the Company to issue commercial paper are affected by its debt credit ratings published by S&P, Moody's Investors Service, Inc. and Fitch Ratings. A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets.

Financial accounting requirements regarding exploration and production activities are expected to negatively affect the Company's profitability.

The Company accounts for its exploration and production activities under the full cost method of accounting. Each quarter, the Company must perform a "ceiling test" calculation, comparing the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses a 12-month historical average price for oil and natural gas (based on first day of the month prices and adjusted for hedging). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material. For the fiscal year ended September 30, 2015, the Company recognized pre-tax impairment charges on its oil and natural gas properties of $1.1 billion. For the quarter ended December 31, 2015, the Company recognized a pre-tax impairment charge on its oil and natural gas properties of $435.5 million. Given the potential that oil and natural gas prices could stay at low levels in future months, and the expected loss of significantly higher prices from the 12-month historical average that will be used in the ceiling test for the remaining quarters of fiscal 2016, the Company expects to experience additional significant ceiling test impairments in each of those quarters (the second, third and fourth quarters of fiscal 2016).

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

On October 1, 2015, the Company issued a total of 4,200 unregistered shares of Company common stock to seven non-employee directors of the Company then serving on the Board of Directors of the Company, 600 shares to each such director. All of these unregistered shares were issued under the Company's 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors' services during the quarter ended December 31, 2015. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased [(a)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under Share Repurchase Plans or Programs [(b)]
Oct. 1 - 31, 2015	354	$50.24	—	6,971,019
Nov. 1 - 30, 2015	—	N/A	—	6,971,019
Dec. 1 - 31, 2015	35,734	$41.25	—	6,971,019
Total	36,088	$41.34	—	6,971,019

(a) Represents shares of common stock of the Company tendered to the Company by holders of stock options, SARs, restricted stock units or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended December 31, 2015, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program.

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

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Item 6. Exhibits

Exhibit Number	Description of Exhibit
10.1	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan.
10.2	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan.
10.3	Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan.
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended December 31, 2015 and the Fiscal Years Ended September 30, 2012 through 2015.
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statements of Income for the Twelve Months Ended December 31, 2015 and 2014.
101	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the three months ended December 31, 2015 and 2014, (ii) the Consolidated Statements of Comprehensive Income for the three months ended December 31, 2015 and 2014, (iii) the Consolidated Balance Sheets at December 31, 2015 and September 30, 2015, (iv) the Consolidated Statements of Cash Flows for the three months ended December 31, 2015 and 2014 and (v) the Notes to Condensed Consolidated Financial Statements.

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

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SIGNATURES

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

NATIONAL FUEL GAS COMPANY
(Registrant)

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

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

Date: February 5, 2016