NATIONAL FUEL GAS CO
Form 10-Q
February 03, 2017
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended December 31, 2016
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, 2017: 85,330,867 shares.

Table of Contents

GLOSSARY OF TERMS

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

National Fuel Gas Companies	
Company	The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
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	
2016 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2016
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

2

Table of Contents

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.
Exploratory well	A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.
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.

Table of Contents

Open Season	A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
Precedent Agreement	An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called "conditions precedent") happen, usually within a specified time.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (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.

Table of Contents

INDEX	Page

• 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.

Table of Contents

Part I. Financial Information

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

	Three Months Ended December 31,	
(Thousands of Dollars, Except Per Common Share Amounts)	2016	2015
INCOME		
Operating Revenues:		
Utility and Energy Marketing Revenues	$207,780	$168,832
Exploration and Production and Other Revenues	161,694	152,884
Pipeline and Storage and Gathering Revenues	53,026	53,479
	422,500	375,195
Operating Expenses:		
Purchased Gas	70,243	42,068
Operation and Maintenance:		
Utility and Energy Marketing	50,422	47,549
Exploration and Production and Other	30,461	45,575
Pipeline and Storage and Gathering	22,660	19,568
Property, Franchise and Other Taxes	20,379	20,357
Depreciation, Depletion and Amortization	56,196	70,551
Impairment of Oil and Gas Producing Properties	—	435,451
	250,361	681,119
Operating Income (Loss)	172,139	(305,924)
Other Income (Expense):		
Interest Income	1,600	1,799
Other Income	1,614	2,418
Interest Expense on Long-Term Debt	(29,103)	(30,372)
Other Interest Expense	(910)	(1,380)
Income (Loss) Before Income Taxes	145,340	(333,459)
Income Tax Expense (Benefit)	56,432	(144,350)
Net Income (Loss) Available for Common Stock	88,908	(189,109)
EARNINGS REINVESTED IN THE BUSINESS		
Balance at Beginning of Period	676,361	1,103,200
	765,269	914,091
Dividends on Common Stock	(34,544)	(33,472)
Cumulative Effect of Adoption of Authoritative Guidance for Stock-Based Compensation	31,916	—
Balance at December 31	$762,641	$880,619
Earnings Per Common Share:		
Basic:		

Net Income (Loss) Available for Common Stock	$1.04	$(2.23)
Diluted:		
Net Income (Loss) Available for Common Stock	$1.04	$(2.23)
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	85,189,851	84,651,233
Used in Diluted Calculation	85,797,989	84,651,233
Dividends Per Common Share:		
Dividends Declared	$0.405	$0.395

See Notes to Condensed Consolidated Financial Statements

Table of Contents

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

	Three Months Ended December 31,	
(Thousands of Dollars)	2016	2015
Net Income (Loss) Available for Common Stock	$88,908	$(189,109)
Other Comprehensive Income (Loss), Before Tax:		
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(883)	(638)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(52,501)	65,372
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	(741)	—
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(30,717)	(57,170)
Other Comprehensive Income (Loss), Before Tax	(84,842)	7,564
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(344)	(191)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(22,052)	20,676
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	(273)	—
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(12,954)	(18,005)
Income Taxes – Net	(35,623)	2,480
Other Comprehensive Income (Loss)	(49,219)	5,084
Comprehensive Income (Loss)	$39,689	$(184,025)

See Notes to Condensed Consolidated Financial Statements

Table of Contents

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2016	September 30, 2016
ASSETS		
Property, Plant and Equipment	$ 9,620,006	$ 9,539,581
Less - Accumulated Depreciation, Depletion and Amortization	5,133,877	5,085,099
	4,486,129	4,454,482
Current Assets		
Cash and Temporary Cash Investments	136,493	129,972
Hedging Collateral Deposits	—	1,484
Receivables – Net of Allowance for Uncollectible Accounts of $22,701 and $21,109, Respectively	161,025	133,201
Unbilled Revenue	59,121	18,382
Gas Stored Underground	23,431	34,332
Materials and Supplies - at average cost	34,170	33,866
Unrecovered Purchased Gas Costs	3,697	2,440
Other Current Assets	49,778	59,354
	467,715	413,031
Other Assets		
Recoverable Future Taxes	179,941	177,261
Unamortized Debt Expense	1,556	1,688
Other Regulatory Assets	323,448	320,750
Deferred Charges	22,215	20,978
Other Investments	114,721	110,664
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	17,960	17,649
Fair Value of Derivative Financial Instruments	42,065	113,804
Other	491	604
	707,873	768,874
Total Assets	$ 5,661,717	$ 5,636,387

See Notes to Condensed Consolidated Financial Statements

Table of Contents

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2016	September 30, 2016
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 85,292,570 Shares and 85,118,886 Shares, Respectively	$ 85,293	$ 85,119
Paid in Capital	775,868	771,164
Earnings Reinvested in the Business	762,641	676,361
Accumulated Other Comprehensive Loss	(54,859)	(5,640)
Total Comprehensive Shareholders' Equity	1,568,943	1,527,004
Long-Term Debt, Net of Unamortized Discount and Debt Issuance Costs	2,086,817	2,086,252
Total Capitalization	3,655,760	3,613,256
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	—	—
Accounts Payable	113,136	108,056
Amounts Payable to Customers	3,231	19,537
Dividends Payable	34,544	34,473
Interest Payable on Long-Term Debt	28,985	34,900
Customer Advances	13,779	14,762
Customer Security Deposits	16,692	16,019
Other Accruals and Current Liabilities	88,519	74,430
Fair Value of Derivative Financial Instruments	7,312	1,560
	306,198	303,737
Deferred Credits		
Deferred Income Taxes	803,166	823,795
Taxes Refundable to Customers	93,940	93,318
Unamortized Investment Tax Credit	340	383
Cost of Removal Regulatory Liability	195,544	193,424
Other Regulatory Liabilities	104,054	99,789
Pension and Other Post-Retirement Liabilities	272,672	277,113
Asset Retirement Obligations	113,194	112,330
Other Deferred Credits	116,849	119,242
	1,699,759	1,719,394
Commitments and Contingencies (Note 6)	—	—
Total Capitalization and Liabilities	$ 5,661,717	$ 5,636,387

See Notes to Condensed Consolidated Financial Statements

9

Table of Contents

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

	Three Months Ended December 31,	
(Thousands of Dollars)	2016	2015
OPERATING ACTIVITIES		
Net Income (Loss) Available for Common Stock	$88,908	$(189,109)
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	56,196	70,551
Deferred Income Taxes	44,852	(140,013)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	—	(226)
Stock-Based Compensation	2,482	960
Other	3,607	3,418
Change in:		
Hedging Collateral Deposits	1,484	1,573
Receivables and Unbilled Revenue	(67,395)	(31,150)
Gas Stored Underground and Materials and Supplies	10,597	3,466
Unrecovered Purchased Gas Costs	(1,257)	—
Other Current Assets	9,576	(5,254)
Accounts Payable	18,805	(20,784)
Amounts Payable to Customers	(16,306)	(11,702)
Customer Advances	(983)	7,189
Customer Security Deposits	673	267
Other Accruals and Current Liabilities	5,919	(14,353)
Other Assets	(8,389)	885
Other Liabilities	(4,122)	2,904
Net Cash Provided by Operating Activities	144,647	114,073
INVESTING ACTIVITIES		
Capital Expenditures	(106,053)	(186,437)
Net Proceeds from Sale of Oil and Gas Producing Properties	5,759	10,574
Other	(4,297)	(15,756)
Net Cash Used in Investing Activities	(104,591)	(191,619)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	—	31,400
Excess Tax Benefits Associated with Stock-Based Compensation Awards	—	226
Dividends Paid on Common Stock	(34,473)	(33,415)
Net Proceeds from Issuance of Common Stock	938	2,068
Net Cash (Used in) Provided by Financing Activities	(33,535)	279
Net Increase (Decrease) in Cash and Temporary Cash Investments	6,521	(77,267)
Cash and Temporary Cash Investments at October 1	129,972	113,596
Cash and Temporary Cash Investments at December 31	$136,493	$36,329

Supplemental Disclosure of Cash Flow Information

Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$48,965	$93,983
Receivable from Sale of Oil and Gas Producing Properties	$20,795	$94,364

See Notes to Condensed Consolidated Financial Statements

Table of Contents

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 Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

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

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments (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, 2016, 2015 and 2014 that are included in the Company's 2016 Form 10-K. The consolidated financial statements for the year ended September 30, 2017 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, 2016 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2017. 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 Statements of Cash Flows. For purposes of the Consolidated Statements 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 net realizable value, 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 $1.7 million at December 31, 2016, 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 $126.7 million and $135.3 million at December 31, 2016 and September 30, 2016, respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with

Table of Contents

settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. At December 31, 2016, the ceiling exceeded the book value of the oil and gas properties by approximately $71.5 million. In adjusting estimated future cash flows for hedging under the ceiling test at December 31, 2016, estimated future net cash flows were increased by $169.3 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. On June 13, 2016, Seneca and IOG executed an extension of the joint development agreement. Under the terms of the extended agreement, Seneca and IOG will jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. The extended joint development agreement gives IOG the option to participate in a 7-well Marcellus pad that is expected to be completed before December 31, 2017, which, if exercised, would increase the maximum number of joint development wells to 82. Under the original joint development agreement, IOG had committed to develop 42 Marcellus wells. IOG will hold an 80% working interest in all of the joint development wells. In total, IOG is expected to fund approximately $325 million for its 80% working interest in the 75 joint development wells. As of December 31, 2016, Seneca had received $143.1 million of cash ($137.3 million in fiscal 2016 and $5.8 million in the quarter ended December 31, 2016) and had recorded a $20.8 million receivable in recognition of IOG funding that is due to Seneca for costs previously incurred to develop a portion of the first 75 joint development wells. The cash proceeds and receivable were recorded by Seneca as a $163.9 million reduction of property, plant and equipment. 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 56 of the joint development wells. In the remaining 19 wells, Seneca retains a 20% working and net revenue interest. Seneca's working interest under the agreement will increase to 85% after IOG achieves a 15% internal rate of return.
Accumulated Other Comprehensive Loss. The components of Accumulated Other Comprehensive Loss and changes for the three months ended December 31, 2016 and 2015, 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, 2016				
Balance at October 1, 2016	$ 64,782	$ 6,054	$ (76,476)	$ (5,640)
Other Comprehensive Gains and Losses Before Reclassifications	(30,449)	(539)	—	(30,988)
Amounts Reclassified From Other Comprehensive Income (Loss)	(17,763)	(468)	—	(18,231)
Balance at December 31, 2016	$ 16,570	$ 5,047	$ (76,476)	$ (54,859)
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
Amounts Reclassified From Other Comprehensive Income (Loss)	(39,165)	—	—	(39,165)
Balance at December 31, 2015	$ 162,728	$ 5,522	$ (69,794)	$ 98,456

12

Table of Contents

Reclassifications Out of Accumulated Other Comprehensive Loss. The details about the reclassification adjustments out of accumulated other comprehensive loss for the three months ended December 31, 2016 and 2015 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 Loss Three Months Ended December 31, 2016	2015	Affected Line Item in the Statement Where Net Income (Loss) is Presented
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	$31,320	$56,327	Operating Revenues
Commodity Contracts	(460)	920	Purchased Gas
Foreign Currency Contracts	(143)	(77)	Operation and Maintenance Expense
Gains (Losses) on Securities Available for Sale	741	—	Other Income
	31,458	57,170	Total Before Income Tax
	(13,227)	(18,005)	Income Tax Expense
	$18,231	$39,165	Net of Tax

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

	At December 31, 2016	At September 30, 2016
Prepayments	$ 7,406	$ 10,919
Prepaid Property and Other Taxes	15,054	13,138
Federal Income Taxes Receivable	3,514	11,758
State Income Taxes Receivable	4,292	3,961
Fair Values of Firm Commitments	41	3,962
Regulatory Assets	19,471	15,616
	$ 49,778	$ 59,354

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

	At December 31, 2016	At September 30, 2016
Accrued Capital Expenditures	$ 29,052	$ 26,796
Regulatory Liabilities	17,984	14,725
Reserve for Gas Replacement	1,700	—
Fair Values of Firm Commitments	3,832	—
Other	35,951	32,909

$ 88,519	$ 74,430

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. For the quarter ended December 31, 2016, 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 317,686 shares excluded as being antidilutive for the quarter ended December 31, 2016. As the Company recognized a net loss for the quarter ended December 31, 2015, the aforementioned potentially dilutive securities, amounting to 394,205 shares, were not recognized in the diluted earnings per share calculation for the quarter ended December 31, 2015.

Stock-Based Compensation. The Company granted 184,148 performance shares during the quarter ended December 31, 2016. The weighted average fair value of such performance shares was $56.39 per share for the quarter ended December 31, 2016. 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, 2016 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2016 to September 30, 2019. 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, 2016 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2016 to September 30, 2019. 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 85,643 non-performance based restricted stock units during the quarter ended December 31, 2016. The weighted average fair value of such non-performance based restricted stock units was $52.12 per share for the quarter ended December 31, 2016. 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, 2016.

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. Working towards this implementation date, the Company is currently evaluating the guidance and the various issues identified by industry based revenue recognition task forces and intends to begin analyzing its contractual arrangements with customers in the second half of fiscal 2017.

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

Table of Contents

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.

In February 2016, the FASB issued authoritative guidance requiring organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by all leases, regardless of whether they are considered to be capital leases or operating leases. The FASB’s previous authoritative guidance required organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by capital leases while excluding operating leases from balance sheet recognition. The new authoritative guidance will be effective as of the Company’s first quarter of fiscal 2020, with early adoption permitted. The Company does not anticipate early adoption and is currently evaluating the provisions of the revised guidance.

In March 2016, the FASB issued authoritative guidance simplifying several aspects of the accounting for stock-based compensation. The Company adopted this guidance effective as of October 1, 2016, recognizing a cumulative effect adjustment that increased retained earnings by $31.9 million. The cumulative effect represents the tax benefit of previously unrecognized tax deductions in excess of stock compensation recorded for financial reporting purposes. On a prospective basis, the tax effect of all future differences between stock compensation recorded for financial reporting purposes and actual tax deductions for stock compensation will be recognized upon vesting or settlement as income tax expense or benefit in the income statement. From a statement of cash flows perspective, the tax benefits relating to differences between stock compensation recorded for financial reporting purposes and actual tax deductions for stock compensation are now included in cash provided by operating activities instead of cash provided by financing activities. The changes to the statement of cash flows have been applied prospectively and prior periods have not been adjusted.

In November 2016, the FASB issued authoritative guidance related to the presentation of restricted cash on the statement of cash flows. The new guidance requires restricted cash and cash equivalents be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows, and requires disclosure of how cash and cash equivalents on the statement of cash flows reconciles to the balance sheet. The Company considers hedging collateral deposits to be restricted cash. The new authoritative guidance will be effective as of the Company’s first quarter of fiscal 2019, with early adoption permitted. The Company is currently evaluating whether it should adopt this guidance earlier than the first quarter of fiscal 2019.

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.

Table of Contents

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, 2016 and September 30, 2016. 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, 2016				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[1]	Total[1]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$119,601	$—	$ —	$ —	$119,601
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	8,878	—	—	(4,446)	4,432
Over the Counter Swaps – Gas and Oil	—	62,093	—	(24,460)	37,633
Other Investments:					
Balanced Equity Mutual Fund	32,965	—	—	—	32,965
Fixed Income Mutual Fund	38,290	—	—	—	38,290
Common Stock – Financial Services Industry	3,666	—	—	—	3,666
Total	$203,400	$62,093	$ —	$ (28,906)	$236,587
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$4,446	$—	$ —	$ (4,446)	$—
Over the Counter Swaps – Gas and Oil	—	29,057	—	(24,460)	4,597
Foreign Currency Contracts	—	2,715	—	—	2,715
Total	$4,446	$31,772	$ —	$ (28,906)	$7,312
Total Net Assets/(Liabilities)	$198,954	$30,321	$ —	$ —	$229,275

Recurring Fair Value Measures	At fair value as of September 30, 2016				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[1]	Total[1]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$114,895	$—	$ —	$ —	$114,895
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	2,623	—	—	(2,276)	347
Over the Counter Swaps – Gas and Oil	—	119,654	—	(3,860)	115,794
Foreign Currency Contracts	—	—	—	(2,337)	(2,337)
Other Investments:					
Balanced Equity Mutual Fund	36,658	—	—	—	36,658
Fixed Income Mutual Fund	31,395	—	—	—	31,395
Common Stock – Financial Services Industry	2,902	—	—	—	2,902
Hedging Collateral Deposits	1,484	—	—	—	1,484
Total	$189,957	$119,654	$ —	$ (8,473)	$301,138
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$2,276	$—	$ —	$ (2,276)	$—
Over the Counter Swaps – Gas and Oil	—	5,322	—	(3,860)	1,462
Foreign Currency Contracts	—	2,337	—	(2,337)	—

Total	$2,276	$7,659	$ —$	(8,473)	$1,462
Total Net Assets/(Liabilities)	$187,681	$111,995	$ —$	—	$299,676

(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, 2016 and September 30, 2016, 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. At September 30, 2016, hedging

Table of Contents

collateral deposits were $1.5 million, which were associated with these futures contracts and have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at December 31, 2016 and September 30, 2016 consist of natural gas price swap agreements used in the Company’s Exploration and Production and Energy Marketing segments, 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 derivative financial instruments reported in Level 2 at December 31, 2016 also include basis hedge swap agreements used in the Company's Energy Marketing 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 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, 2016, 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.

The table listed below provides a reconciliation of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the quarter ended December 31, 2015. For the quarter ended December 31, 2016, there were no assets or liabilities measured at fair value and classified as Level 3. The Company's Exploration and Production segment had a small portion of their crude oil price swap agreements reported as Level 3 at October 1, 2015 that settled prior to December 31, 2015. For the quarters ended December 31, 2016 and December 31, 2015, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the period presented in the table below. All settlements of the derivative financial instruments are reflected in the Gains/Losses Realized and Included in Earnings column of the table 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.

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, 2016		September 30, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$2,086,817	$2,229,440	$2,086,252	$2,255,562

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.

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 $39.8 million at December 31, 2016 and $39.7 million at September 30, 2016. The fair value of the equity mutual fund was $33.0 million at December 31, 2016 and $36.7 million at September 30, 2016. The gross unrealized gain on this equity mutual fund was $5.7 million at December 31, 2016 and $7.9 million at September 30, 2016. The fair value of the fixed income mutual fund was $38.3 million at December 31, 2016 and $31.4 million at September 30, 2016. The gross unrealized loss on this fixed income mutual fund was $0.1 million at December 31, 2016 and the gross unrealized gain on this fixed income mutual fund was less than $0.1 million at September 30, 2016. The fair value of the stock of an insurance company was $3.7 million at December 31, 2016 and $2.9 million at September 30, 2016. The gross unrealized gain on this stock was $2.4 million at December 31, 2016 and $1.6 million at September 30, 2016. 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, 2016 and September 30, 2016. 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, 2016, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	156.3	Bcf (short positions)
Natural Gas	1.3	Bcf (long positions)
Crude Oil	2,334,000	Bbls (short positions)

As of December 31, 2016, the Company was hedging a total of $75.5 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts (long positions).

Table of Contents

As of December 31, 2016, the Company had $28.6 million ($16.6 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $23.9 million ($13.8 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.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended December 31, 2016 and 2015 (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,	
	2016	2015		2016	2015		2016	2015
Commodity Contracts	$(50,444)	$65,341	Operating Revenue	$31,320	$56,327	Operating Revenue	$(100)	$137
Commodity Contracts	(1,536)	2,213	Purchased Gas	(460)	920	Not Applicable	—	—
Foreign Currency Contracts	(521)	(2,182)	Operation and Maintenance Expense	(143)	(77)	Not Applicable	—	—
Total	$(52,501)	$65,372		$30,717	$57,170		$(100)	$137

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, 2016, the Company’s Energy Marketing segment had fair value hedges covering approximately 12.6 Bcf (12.1 Bcf of fixed price sales commitments, 0.1 Bcf of fixed price purchase commitments and 0.4 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 Three Months Ended December 31, 2016 (In Thousands)	Amount of Gain or (Loss) on the Hedged Item Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2016 (In Thousands)
Commodity Contracts	Operating Revenues	$ 5,044	$ (5,044)
Commodity Contracts	Purchased Gas	$ (44)	$ 44
		$ 5,000	$ (5,000)

19

Economic Hedges

For derivative instruments that do not qualify as either a cash flow hedge or fair value hedge, all gains and losses are recognized in the Consolidated Statement of Income. As of December 31, 2016, the Company's Energy Marketing segment had derivative contracts (swaps) outstanding to hedge the difference between natural gas prices at local purchase points and NYMEX quoted natural gas prices on forecasted sales of 0.3 Bcf of gas to mitigate the risk of decreasing revenues and earnings. The Company did not have any economic hedges during fiscal 2016. The aggregate derivative gain associated with such contracts for the quarter ended December 31, 2016 was $0.2 million. This gain was reported as a component of Operating Revenues in the Consolidated Statement of Income.

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 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 ten are in a net gain position. On average, the Company had $3.7 million of credit exposure per counterparty in a gain position at December 31, 2016. The maximum credit exposure per counterparty in a gain position at December 31, 2016 was $10.3 million. As of December 31, 2016, no collateral was received from the counterparties by the Company. The Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties' credit ratings declined to levels at which the counterparties were required to post collateral.

As of December 31, 2016, fourteen 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, 2016, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $24.4 million according to the Company’s internal model (discussed in Note 2 — Fair Value Measurements). At December 31, 2016, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $6.6 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, 2016.

For its exchange traded futures contracts, no hedging collateral deposits were required to be posted by the Company as of December 31, 2016 and hedging collateral deposits of $2.2 million were received by the Company. These hedging collateral deposits are recorded as a component of Accounts Payable on the Consolidated Balance Sheet. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts or receives 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.

Table of Contents

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,	
	2016	2015
Current Income Taxes		
Federal	$8,245	$(8,227)
State	3,335	3,890
Deferred Income Taxes		
Federal	36,418	(97,705)
State	8,434	(42,308)
	56,432	(144,350)
Deferred Investment Tax Credit	(43)	(87)
Total Income Taxes	$56,389	$(144,437)
Presented as Follows:		
Other Income	(43)	(87)
Income Tax Expense (Benefit)	56,432	(144,350)
Total Income Taxes	$56,389	$(144,437)

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,	
	2016	2015
U.S. Income (Loss) Before Income Taxes	$145,297	$(333,546)
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate of 35%	$50,854	$(116,741)
State Income Taxes (Benefit)	7,650	(24,972)
Miscellaneous	(2,115)	(2,724)
Total Income Taxes	$56,389	$(144,437)

Note 5 - Capitalization

Common Stock. During the three months ended December 31, 2016, the Company issued 19,000 original issue shares of common stock as a result of stock option and SARs exercises, 74,047 original issue shares of common stock for restricted stock units that vested and 43,484 original issue shares of common stock for performance shares that vested. In addition, the Company issued 46,352 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 26,995 original issue shares of common stock for the Company’s 401(k) plans. The Company also issued 4,957 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, 2016. 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, 2016, 41,151 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.

Table of Contents

Current Portion of Long-Term Debt. None of the Company’s long-term debt at December 31, 2016 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, 2016, 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 $3.8 million. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 11 years.

The Company's estimated liability for clean-up costs discussed above includes a $2.1 million estimated liability related to the remediation of 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 has also been completed. Restoration work is substantially complete.

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 2016 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 2016 Form 10-K. A listing of segment assets at December 31, 2016 and September 30, 2016 is shown in the tables below.

Quarter Ended December 31, 2016
(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	$160,932	$53,000	$26	$170,971	$36,809	$421,738	$554	$208	$422,500
Intersegment Revenues	$—	$22,155	$27,840	$1,826	$19	$51,840	$—	$(51,840)	$—
Segment Profit: Net Income (Loss)	$35,080	$19,368	$10,981	$21,175	$1,782	$88,386	$(179)	$701	$88,908

22

Table of Contents

(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, 2016	$1,267,468	$1,698,279	$552,855	$2,071,276	$77,454	$5,667,332	$76,857	$(82,472)	$5,661,717
At September 30, 2016	$1,323,081	$1,680,734	$534,259	$2,021,514	$63,392	$5,622,980	$77,138	$(63,731)	$5,636,387

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)

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,	2016	2015	2016	2015
Service Cost	$2,992	$2,928	$612	$583
Interest Cost	9,596	10,579	4,752	5,096
Expected Return on Plan Assets	(14,929)	(14,842)	(7,865)	(7,883)
Amortization of Prior Service Cost (Credit)	264	308	(107)	(228)
Amortization of Losses	10,672	8,062	4,604	1,382
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	535	1,906	1,312	4,121
Net Periodic Benefit Cost	$9,130	$8,941	$3,308	$3,071

(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, 2016, the Company contributed $15.1 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $0.9 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2017, the Company expects to contribute up to $5.0 million to the Retirement Plan. In the remainder of 2017, the Company expects its contributions to the VEBA trusts and 401(h) accounts to be in the range of $2.0 million to $4.0 million.

Note 9 – Regulatory Matters

On April 28, 2016, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by approximately $41.7 million. Distribution Corporation explained in the filing that its request for rate relief was necessitated by a revenue requirement driven primarily by rate base growth, higher operating expense and higher depreciation expense that are not reflected in current rates, among other things. The rate filing includes a proposal for system infrastructure modernization that includes the acceleration of Distribution Corporation's replacement of certain gas mains, which are of a type generically classified by the NYPSC as "leak prone pipe". After a full evidentiary hearing in early October 2016, on October 19, 2016, the Company filed a Notice of Impending Confidential Settlement Negotiations notifying the NYPSC that Distribution Corporation, Department of Public Service Staff and other interested parties were entering

Table of Contents

into settlement discussions. On November 23, 2016, the Company filed a Notice of Discontinued Settlement Negotiations with the NYPSC advising that a settlement had not been reached and the parties were returning to the litigation schedule established in the case. On January 23, 2017, the administrative law judge assigned to the proceeding issued a recommended decision (RD) based on a review and assessment of the evidence presented in the case. The RD, as revised on January 26, 2017, recommends a rate increase designed to provide additional annual revenues of $8.5 million. The recommended equity ratio, subject to updates, is 42.3%, and is based on the Company's equity ratio, and the recommended cost of equity, subject to updates, is 8.6%. The NYPSC is not bound to accept the RD, and may accept, reject or modify Distribution Corporation's filing or the RD. Assuming standard procedure, rates would become effective in late April 2017. The outcome of the proceeding cannot be ascertained at this time.

FERC Rate Proceedings

Supply Corporation's current rate 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. Under the settlement, Supply Corporation reduced its maximum reservation, capacity, demand and deliverability rates by 2% on November 1, 2015 and reduced those rates by an additional 2% on November 1, 2016.

By order dated January 21, 2016, the FERC began a NGA Section 5 rate review of Empire's rates. As required by that order, Empire filed a Cost and Revenue Study on April 5, 2016. On May 25, 2016, Empire reached a settlement in principle on this matter that would, among other things, reduce certain of Empire's maximum transportation rates over a 14-month period, which, based on current contracts, is estimated to reduce Empire's revenues on a yearly basis by between $3 million to $4 million. The settlement also reduces Empire's depreciation rate from 2.5% to 2%. In addition, the settlement provides an annual revenue sharing mechanism, pursuant to which non-expansion transportation revenues exceeding $73.5 million are shared on a tiered basis. Under the settlement, Empire will be required to make a general rate filing no later than July 1, 2021. On December 13, 2016, the FERC issued an order approving the settlement. The settlement is not expected to have a material impact on the Company's financial condition.

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, 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 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, 2016 compared to the quarter ended December 31, 2015, the Company experienced an increase in earnings of $278.0 million, primarily due to higher earnings in the Exploration and Production segment. During the quarter ended December 31, 2015, the Company recorded an impairment charge of $435.5 million ($252.6 million after-tax) that did not recur during the quarter ended December 31, 2016. In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Such costs are subject to a quarterly ceiling test prescribed by SEC Regulation S-X Rule 4-10 that determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. At December 31, 2015, due to significant declines in crude oil and natural gas commodity prices over the previous twelve months, the book value of the Company's oil and gas properties exceeded the ceiling, resulting in the impairment charge mentioned above. For further discussion of the ceiling test 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, in its Pipeline and Storage segment, is awaiting FERC authorization to proceed with its $455 million project to move significant prospective Marcellus production from Seneca’s Western Development Area at Clermont to an Empire interconnection with TransCanada Pipeline at Chippawa and an interconnection with Tennessee Gas Pipeline’s 200 Line in East Aurora, New York (“Northern Access 2016”). While the Company believes that it will receive FERC authorization in the first half of fiscal 2017, the NYDEC must also provide a water quality certificate for this project. A decision by the NYDEC is expected by April 2017. The anticipated in-service date for this project is in the second quarter of the Company's 2018 fiscal year. Capital expenditures in the Pipeline and Storage segment for fiscal 2017 have been reduced from approximately $415 million to approximately $225 million.
From a financing perspective, given the significant ceiling test impairments recorded during the years ended September 30, 2016 and September 30, 2015, the Company’s existing 1974 indenture covenants preclude the Company from issuing additional long-term unsecured indebtedness until the second half of fiscal 2017. The Company expects to use cash on hand and cash from operations and, if necessary, short-term borrowings to meet its capital expenditure needs for fiscal 2017. The need for longer-term financing options beyond that time frame are currently being evaluated.
CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2016 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. At December 31, 2016, the ceiling exceeded the book value of the oil and gas properties by approximately $71.5 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended December 31,

Table of Contents

2016, based on posted Midway Sunset prices, was $36.28 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, 2016, based on the quoted Henry Hub spot price for natural gas, was $2.48 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, 2016.) If crude oil prices were $5 per Bbl lower than the average used at December 31, 2016, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $33.6 million. The following table further illustrates the sensitivity of the ceiling test calculation to commodity price changes, specifically showing the impairment that the Company would have recorded at December 31, 2016 if natural gas prices were $0.25 per MMBtu lower than the average used at December 31, 2016, and the impairment that the Company would have recorded at December 31, 2016 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, 2016 (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 Natural Gas Prices	$5.00/Bbl Decrease in Crude Oil Prices	$0.25/MMBtu Decrease in Natural Gas Prices and $5.00/Bbl Decrease in Crude Oil Prices
Calculated Impairment under Sensitivity Analysis	$ 37.8	$ —	$ 75.5

It is difficult to predict what factors could lead to future impairments under the SEC's full cost ceiling test. Fluctuations in or subtractions from proved reserves and significant fluctuations in oil and gas prices have an impact on the amount of the ceiling at any point in time. For a more complete discussion of the full cost method of accounting, refer to "Oil and Gas Exploration and Development Costs" under "Critical Accounting Estimates" in Item 7 of the Company's 2016 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $88.9 million for the quarter ended December 31, 2016 compared to a loss of $189.1 million for the quarter ended December 31, 2015. The increase in earnings of $278.0 million is primarily a result of higher earnings in the Exploration and Production segment, Gathering segment, Utility segment and Energy Marketing segment. Lower earnings in the Pipeline and Storage segment and Corporate category, as well as a loss in the All Other category, partially offset these increases.

The Company's loss for the quarter ended December 31, 2015 includes 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.

26

Table of Contents

Earnings (Loss) by Segment

(Thousands)	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Exploration and Production	$35,080	$(237,086)	$272,166
Pipeline and Storage	19,368	21,276	(1,908)
Gathering	10,981	4,921	6,060
Utility	21,175	18,606	2,569
Energy Marketing	1,782	1,223	559
Total Reportable Segments	88,386	(191,060)	279,446
All Other	(179)	189	(368)
Corporate	701	1,762	(1,061)
Total Consolidated	$88,908	$(189,109)	$278,017

Exploration and Production

Exploration and Production Operating Revenues

(Thousands)	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Gas (after Hedging)	$120,564	$106,174	$ 14,390
Oil (after Hedging)	39,457	44,730	(5,273)
Gas Processing Plant	761	636	125
Other	150	425	(275)
	$160,932	$151,965	$ 8,967

Production Volumes

	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Gas Production (MMcf)			
Appalachia	39,807	32,788	7,019
West Coast	776	783	(7)
Total Production	40,583	33,571	7,012
Oil Production (Mbbl)			
Appalachia	—	6	(6)
West Coast	721	742	(21)
Total Production	721	748	(27)

Table of Contents

Average Prices

	Three Months Ended December 31,		
	2016	2015	Increase (Decrease)
Average Gas Price/Mcf			
Appalachia	$2.35	$1.98	$ 0.37
West Coast	$4.24	$3.65	$ 0.59
Weighted Average	$2.39	$2.02	$ 0.37
Weighted Average After Hedging	$2.97	$3.16	$ (0.19)
Average Oil Price/Bbl			
Appalachia	N/M	$39.78	N/M
West Coast	$43.69	$36.05	$ 7.64
Weighted Average	$43.82	$36.08	$ 7.74
Weighted Average After Hedging	$54.71	$59.76	$ (5.05)

N/M - Not Meaningful

2016 Compared with 2015

Operating revenues for the Exploration and Production segment increased $9.0 million for the quarter ended December 31, 2016 as compared with the quarter ended December 31, 2015. Gas production revenue after hedging increased $14.4 million primarily due to a large increase in gas production partially offset by a $0.19 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging decreased $5.3 million due to a $5.05 per Bbl decrease in the weighted average price of oil after hedging coupled with a decrease in crude oil production.

The Exploration and Production segment's earnings for the quarter ended December 31, 2016 were $35.1 million compared with a loss of $237.1 million for the quarter ended December 31, 2015. The increase in earnings primarily reflects the non-recurrence of the aforementioned impairment charge ($252.6 million). It also reflects lower depletion expense ($9.7 million), higher natural gas production ($14.4 million), lower other operating expenses ($1.9 million), lower interest expense ($0.7 million) and the non-recurrence of joint development agreement professional fees ($2.7 million). The decrease in depletion expense is primarily due to a lower level of capitalized costs as a result of the impairment charges recognized in fiscal 2015 and fiscal 2016 partially offset by the impact of an increase in natural gas production. The decrease in other operating expenses is primarily due to a decrease in personnel costs. The decrease in interest expense is largely due to a decrease in the Exploration and Production segment’s short-term borrowings. The joint development agreement professional fees incurred were related to professional services associated with the Marcellus Shale drilling joint development agreement with IOG executed during the quarter ended December 31, 2015 that did not recur during the quarter ended December 31, 2016. These factors, which contributed to increased earnings during the quarter ended December 31, 2016 compared to the quarter ended December 31, 2015, were partially offset by lower crude oil prices after hedging ($2.4 million), lower natural gas prices after hedging ($5.1 million), lower crude oil production ($1.1 million), higher production costs ($0.5 million), and higher income taxes ($0.5 million). The increase in production costs is largely due to an increase in intercompany transportation costs associated with production volume transported by Midstream Corporation offset largely by lower repair costs, equipment, materials and labor associated with operating wells in Appalachia and on the West Coast. The increase in income taxes is due to higher state taxes.

Table of Contents

Pipeline and Storage

Pipeline and Storage Operating Revenues

(Thousands)	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Firm Transportation	$56,749	$56,505	$ 244
Interruptible Transportation	646	975	(329)
	57,395	57,480	(85)
Firm Storage Service	17,273	17,278	(5)
Interruptible Storage Service	12	50	(38)
Other	475	729	(254)
	$75,155	$75,537	$ (382)

Pipeline and Storage Throughput

(MMcf)	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Firm Transportation	190,781	175,832	14,949
Interruptible Transportation	3,046	5,631	(2,585)
	193,827	181,463	12,364

2016 Compared with 2015

Operating revenues for the Pipeline and Storage segment remained relatively flat for the quarter ended December 31, 2016 as compared with the quarter ended December 31, 2015. A decline in operating revenues due to a 2% reduction on November 1, 2015 and an additional 2% reduction on November 1, 2016 in Supply Corporation's rates associated with its rate case settlement, as well as reductions to Empire's rates as of July 1, 2016 related to its rate case settlement, were largely offset by increases in operating revenues due to a full quarter of revenue from Supply Corporation's Northern Access 2015 project, which was placed in service on an interim basis in November 2015 and became fully operational in December 2015, combined with a full quarter of revenue from Empire's Tuscarora Lateral Project, which was placed in service in November 2015.

Transportation volume for the quarter ended December 31, 2016 increased by 12.4 Bcf from the prior year’s quarter. The increase in transportation volume for the quarter primarily reflects the impact of a full quarter of transportation service from the Northern Access 2015 project and the Tuscarora Lateral Project, both of which are discussed in the previous paragraph. 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, 2016 were $19.4 million, a decrease of $1.9 million when compared with earnings of $21.3 million for the quarter ended December 31, 2015. The decrease in earnings is primarily due to higher operating expenses ($1.7 million) and a decrease in the allowance for funds used during construction (equity component) of $0.9 million. The increase in operating expenses primarily reflects higher pension costs, an increase in expense related to the reserve for preliminary project costs and increased personnel costs. The decrease in allowance for funds used during construction reflects the completion of Supply

Corporation’s Westside Expansion and Modernization Project, Supply Corporation's Northern Access 2015 project and Empire's Tuscarora Lateral Project in the first quarter of fiscal 2016. These earnings decreases were offset slightly by a decrease in depreciation expense ($0.4 million). The decrease in depreciation expense was attributable to a decrease in Empire's depreciation rates as of July 1, 2016 associated with Empire's rate case settlement offset partially by the incremental depreciation expense related to expansion projects that were placed in service within the last year.

Table of Contents

Gathering

Gathering Operating Revenues

(Thousands)	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Gathering	$27,840	$18,640	$ 9,200
Processing and Other Revenues	26	125	(99)
	$27,866	$18,765	$ 9,101

Gathering Volume

	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Gathered Volume - (MMcf)	50,569	33,800	16,769

2016 Compared with 2015

Operating revenues for the Gathering segment increased $9.1 million for the quarter ended December 31, 2016 as compared with the quarter ended December 31, 2015. This increase was due to an increase in gathering revenues driven by a 16.8 Bcf increase in gathered volume. The overall increase in gathered volume was due to a 10.3 Bcf increase in gathered volume on Midstream Corporation’s Clermont Gathering System (Clermont), a 2.8 Bcf increase in gathered volume on Midstream Corporation's Trout Run Gathering System (Trout Run), a 2.3 Bcf increase in gathered volume on Midstream Corporation's Covington Gathering System (Covington) and a 1.3 Bcf increase in gathered volume on Midstream Corporation's Wellsboro Gathering System (Wellsboro). Wellsboro was placed into service in November 2016. In addition, the increases in the aforementioned volumes were largely due to increases in Seneca's Marcellus Shale production as Appalachian spot prices improved. The impact of the Northern Access 2015 project being completed in November and December 2015 also led to an increase in gathered volumes.

The Gathering segment’s earnings for the quarter ended December 31, 2016 were $11.0 million, an increase of $6.1 million when compared with earnings of $4.9 million for the quarter ended December 31, 2015. The increase in earnings is mainly due to an increase in gathering revenues ($6.0 million) and lower interest expense ($0.6 million). The increase in gathering revenues is due to the increases in gathered volume discussed above. The decrease in interest expense is the result of an increase in capitalized interest. The increase in revenues was partially offset by higher operating expense ($0.3 million). The increase in operating expenses was largely due to the significant growth of Clermont and its impact on maintenance expense.

Table of Contents

Utility

Utility Operating Revenues

(Thousands)	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Retail Sales Revenues:			
Residential	$116,387	$98,451	$ 17,936
Commercial	15,979	12,105	3,874
Industrial	517	490	27
	132,883	111,046	21,837
Transportation	36,661	33,902	2,759
Off-System Sales	627	—	627
Other	2,626	2,564	62
	$172,797	$147,512	$ 25,285

Utility Throughput

(MMcf)	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Retail Sales:			
Residential	15,764	13,133	2,631
Commercial	2,299	1,827	472
Industrial	77	66	11
	18,140	15,026	3,114
Transportation	19,565	17,615	1,950
Off-System Sales	173	—	173
	37,878	32,641	5,237

Degree Days

Three Months Ended December 31,	Normal	2016	2015	Percent Colder (Warmer) Than Normal(1)	Prior Year(1)
Buffalo	2,253	1,966	1,677	(12.7)%	17.2 %
Erie	2,044	1,750	1,484	(14.4)%	17.9 %

(1) Percents compare actual 2016 degree days to normal degree days and actual 2016 degree days to actual 2015 degree days.

2016 Compared with 2015

Operating revenues for the Utility segment increased $25.3 million for the quarter ended December 31, 2016 as compared with the quarter ended December 31, 2015. The increase largely resulted from a $21.8 million increase in retail gas sales revenues. In addition, there was a $2.8 million increase in transportation revenues, and a $0.6 million increase in off-system sales (due to higher volumes). The increase in retail gas sales revenues was largely a result of higher volumes (due to colder weather) and an increase in the cost of gas sold (per Mcf). The $2.8 million increase in transportation revenues was primarily due to a 2.0 Bcf increase in transportation throughput due to colder weather. Due to profit sharing with retail customers, the margins related to off-system sales are minimal.

Table of Contents

The Utility segment's earnings for the quarter ended December 31, 2016 were $21.2 million, an increase of $2.6 million when compared with earnings of $18.6 million for the quarter ended December 31, 2015. The increase in earnings was largely attributable to the impact of colder weather in fiscal 2017 compared to fiscal 2016 ($3.3 million), higher usage ($1.5 million) and the impact of routine regulatory adjustments ($1.3 million). These were partially offset by the negative earnings impact associated with an increase in operating expenses of $1.9 million (primarily due to higher personnel costs) and an increase in depreciation expense of $1.0 million (largely due to higher plant balances). Usage refers to consumption after factoring out any impact that weather may have had on consumption.

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. For the quarter ended December 31, 2016, the WNC increased earnings by approximately $1.3 million as the weather was warmer than normal. For the quarter ended December 31, 2015, the WNC increased earnings by approximately $2.0 million, as the weather was warmer than normal.

Energy Marketing

Energy Marketing Operating Revenues

(Thousands)	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Natural Gas (after Hedging)	$36,790	$25,196	$ 11,594
Other	38	99	(61)
	$36,828	$25,295	$ 11,533

Energy Marketing Volume

	Three Months Ended December 31, 2016	2015	Increase (Decrease)
Natural Gas – (MMcf)	11,127	10,098	1,029

2016 Compared with 2015

Operating revenues for the Energy Marketing segment increased $11.5 million for the quarter ended December 31, 2016 as compared with the quarter ended December 31, 2015. The increase is primarily due to an increase in gas sales revenue due to a higher average price of natural gas period over period. An increase in volume sold to retail customers as a result of colder weather also contributed to the increase in operating revenues.

The Energy Marketing segment earnings for the quarter ended December 31, 2016 were $1.8 million, an increase of $0.6 million when compared with earnings of $1.2 million for the quarter ended December 31, 2015. This increase in earnings was largely attributable to higher margin of $0.6 million. The increase in margin largely reflects the margin impact associated with the increase in volume sold to retail customers as a result of colder weather during the quarter ended December 31, 2016 compared to the quarter ended December 31, 2015.

Corporate and All Other

2016 Compared with 2015

Corporate and All Other operations operations had earnings of $0.5 million for the quarter ended December 31, 2016, a decrease of $1.5 million when compared with earnings of $2.0 million for the quarter ended December 31, 2015. The earnings decrease for the quarter can be attributed to higher operating expenses of $0.6 million (primarily due to higher personnel costs) and higher income tax expense of $1.1 million.

Table of Contents

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

Interest on long-term debt decreased $1.3 million for the quarter ended December 31, 2016 as compared with the quarter ended December 31, 2015. This decrease is primarily due to an increase in capitalized interest (mostly in Midstream Corporation) which decreased interest expense for the quarter ended December 31, 2016 as compared to the quarter ended December 31, 2015.

CAPITAL RESOURCES AND LIQUIDITY

The Company’s primary sources of cash during the three-month period ended December 31, 2016 consisted of cash provided by operating activities 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 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. These sources of cash were supplemented by net proceeds from the issuance of common stock for both the three months ended December 31, 2016 and December 31, 2015, 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 $144.6 million for the three months ended December 31, 2016, an increase of $30.5 million compared with $114.1 million provided by operating activities for the three months ended

December 31, 2015. The increase in cash provided by operating activities reflects higher cash provided by operating activities in the Exploration and Production segment primarily due to higher cash receipts from natural gas production in the Appalachian region.

Table of Contents

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets totaled $94.6 million during the three months ended December 31, 2016 and $161.5 million during the three months ended December 31, 2015. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Three Months Ended December 31, (Millions)	2016		2015		Increase(Decrease)
Exploration and Production:					
Capital Expenditures	$40.7	(1)	$88.1	(2)	$ (47.4)
Pipeline and Storage:					
Capital Expenditures	25.4	(1)	31.6	(2)	(6.2)
Gathering:					
Capital Expenditures	11.3	(1)	21.8	(2)	(10.5)
Utility:					
Capital Expenditures	17.1	(1)	19.9	(2)	(2.8)
All Other:					
Capital Expenditures	0.1	(1)	0.1	(2)	—
	$94.6		$161.5		$ (66.9)

(1) At December 31, 2016, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $25.3 million, $8.7 million, $7.9 million and $7.1 million, respectively, of non-cash capital expenditures. At September 30, 2016, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $25.2 million, $18.7 million, $5.3 million and $11.2 million, respectively, of non-cash capital expenditures. The capital expenditures for the Exploration and Production segment do not include any proceeds received from the sale of oil and gas assets to IOG under the joint development agreement.

(2) At December 31, 2015, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $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.

Exploration and Production

The Exploration and Production segment capital expenditures for the three months ended December 31, 2016 were primarily well drilling and completion expenditures and included approximately $29.8 million for the Appalachian region (including $16.4 million in the Marcellus Shale area) and $10.9 million for the West Coast region. These amounts included approximately $8.3 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. On June 13, 2016, Seneca and IOG executed an extension of the joint development agreement. Under the terms of the extended agreement, Seneca and IOG will jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. The extended joint development agreement gives IOG the option to participate in an additional 7-well Marcellus pad that is expected to be completed before December 31, 2017, which, if exercised, would increase the maximum number of joint development wells to 82. Under the original joint development agreement, IOG had committed to develop 42 Marcellus wells. As of December 31, 2016, Seneca had received $143.1 million of cash ($137.3 million in fiscal 2016 and $5.8 million in the quarter ended December 31, 2016) and had recorded a $20.8 million receivable in recognition of IOG funding that is due to Seneca for costs previously incurred to develop a portion of the first 75 joint development wells. The cash proceeds and receivable were recorded by Seneca as a $163.9 million reduction of property, plant and equipment. For further discussion of the extended 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, 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.

Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the three months ended December 31, 2016 were mainly for expenditures related to Empire and Supply Corporation's Northern Access 2016 Project ($13.5 million) and Supply Corporation's Line D Expansion Project ($4.2 million), as discussed below. In addition, the Pipeline and Storage segment capital expenditures for the three months ended December 31, 2016 also include additions, improvements and replacements to this segment’s transmission and gas storage systems. The Pipeline and Storage 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), Empire and Supply Corporation's Northern Access 2016 Project ($8.5 million) and Empire and Supply Corporation's Tuscarora Lateral Project ($2.3 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, for those projects for which a reserve had been established, 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, 2016, 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.

Supply Corporation and Empire are developing 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 and an interconnection with TGP's 200 Line in East Aurora, New York (“Northern Access 2016”). The 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 99 miles of largely 24” pipeline and approximately 27,500 horsepower of compression on the two systems. The target in-service date for this project is in the second quarter of the Company's 2018 fiscal year. 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. On July 27, 2016, the FERC issued the Environmental Assessment for the project, completing a significant milestone in the FERC review process. While the Company believes that it will receive FERC authorization in the first half of fiscal 2017, the NYDEC must also provide a water quality certificate for this project. A decision by the NYDEC is expected by April 2017. As of December 31, 2016, approximately $61.7 million has been spent on the Northern Access 2016 project, including $15.5 million that has been spent to study the project, for which no reserve has been established. The remaining $46.2 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. Supply Corporation has executed Service Agreements for a total of 77,500 Dth per day for terms of six to 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 and completed the FERC notice period on February 26, 2016. Although the portion of the project associated with the construction of the Keelor Compressor Station awaits receipt of an air permit from the PaDEP, the target in-service date is November

Table of Contents

1, 2017, with interim service beginning as early as April 1, 2017. As of December 31, 2016, approximately $14.6 million has been capitalized as Construction Work in Progress for the Line D Expansion project.

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, the TGP 200 Line and potentially other on-system points ("Empire North Project"), and is negotiating precedent agreements with prospective shippers for that capacity. The preliminary cost estimate for the Empire North Project is approximately $205 million. As of December 31, 2016, approximately $0.4 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, 2016.

Gathering

The majority of the Gathering segment capital expenditures for the three months ended December 31, 2016 and December 31, 2015 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 the shippers', including Seneca's, long-term plans. As of December 31, 2016, approximately $268.7 million has been spent on the Clermont Gathering System, including approximately $9.1 million spent during the three months ended December 31, 2016, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2016.

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, 2016, the Company has spent approximately $167.8 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, 2016.

Utility

The majority of the Utility segment capital expenditures for the three months ended December 31, 2016 and December 31, 2015 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 also included $2.0 million related to the replacement of the Utility segment's customer information system, which was placed in service in May 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 the remainder of fiscal 2017 to help meet its capital expenditure 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 expects to be precluded from issuing new long-term debt until the second half of fiscal 2017 as a means of financing projects.

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

The Company had no consolidated short-term debt outstanding at December 31, 2016 and September 30, 2016, nor was there any short-term debt outstanding during the quarter ended December 31, 2016. While the Company did not have any outstanding commercial paper and short-term notes payable to banks at December 31, 2016, 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.

On September 9, 2016, the Company entered into a Third Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of 13 banks. During the quarter ended December 31, 2016, the syndicate size was reduced from 14 to 13 banks as a result of a merger between two banks in the syndicate, however the overall size of the commitment has not changed. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through December 5, 2019. The Credit Agreement also provides a $500.0 million 364-day unsecured committed revolving credit facility with 11 of the 13 banks through September 8, 2017. 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 .675 at the last day of any fiscal quarter through September 30, 2017, or .65 at the last day of any fiscal quarter from October 1, 2017 through December 5, 2019. At December 31, 2016, the Company’s debt to capitalization ratio (as calculated under the facility) was .57. The constraints specified in the Credit Agreement would have permitted an additional $1.17 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 .675.

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, 2016, the Company did not have any debt outstanding under the Credit Agreement.

None of the Company’s long-term debt at December 31, 2016 and 2015 had a maturity date within the following twelve-month period.

The Company’s embedded cost of long-term debt was 5.53% at both December 31, 2016 and December 31, 2015.

Under the Company’s existing indenture covenants, at December 31, 2016, the Company expects to be precluded from issuing additional long-term unsecured indebtedness until the second half of fiscal 2017 as a result of impairments of its oil and gas properties recognized during the years ended September 30, 2016 and 2015, as discussed above. The 1974 indenture would not preclude the Company from issuing new indebtedness to replace maturing debt and 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 $98.7 million (or 4.7%) of the Company’s long-term debt (as of December 31, 2016) 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 $22.8 million. These leases have been entered into for the use of compressors, drilling rigs, buildings 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 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, 2016, the Company contributed $15.1 million to its Retirement Plan and $0.9 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2017, the Company expects to contribute up to $5.0 million to the Retirement Plan. In the remainder of 2017, the Company expects its contributions to the VEBA trusts and 401(h) accounts to be in the range of $2.0 million to $4.0 million.

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 have been adopted or 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. While many of the final rules adopted by the CFTC and other regulators place specific conditions on the operations of swap dealers and major swap participants, 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. For example, the Dodd-Frank Act requires that certain swaps be cleared and traded on exchanges or swap execution facilities, with certain exceptions for swaps that end-users such as the Company use to hedge or mitigate commercial risk. While the Company expects to be excluded from these clearing and trading requirements for swaps used to hedge its commercial risks, there may be increased transaction costs or decreased liquidity with respect to entering into such uncleared and non-exchange traded swaps.

Also, during the fourth calendar quarter of 2015, the bank regulators and the CFTC, respectively, adopted final margin rules that apply to swap dealers and major swap participants with respect to uncleared swaps. While these rules do not impose a requirement on swap dealers and major swap participants to collect margin for uncleared swaps from non-financial end users such as the Company, the obligations may increase the costs of uncleared swaps. For example, among other things, to fulfill obligations imposed on them under the rules, swap dealers may seek to negotiate collateral or other credit arrangements in their swap agreements with counterparties, which would increase the cost of transactions in uncleared swaps and affect the Company's liquidity and reduce our available cash. In the fourth quarter of 2016, the CFTC issued a reproposal to its position limit rules that would impose speculative position limits on positions in 28 core physical commodity contracts as well as economically equivalent futures, options and swaps. While the Company does not intend to enter into positions on a speculative basis, such rules could nevertheless impact the ability of the Company to enter into certain derivative hedging transactions with respect to such commodities. If we reduce our use of hedging transactions as a result of final regulations to be issued by the CFTC, our results of operations may become more volatile and our cash flows may be less predictable. 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. Finally, given the additional anti-market manipulation, anti-fraud and disruptive trading practices regulations that prohibit, among other things, fraud and price manipulation in the physical commodities, futures, options and swaps markets, it is difficult to predict how the evolving enforcement priorities of the CFTC will impact our business. Should we violate the laws regulating hedging activities or regulations promulgated by the CFTC, we could be subject to CFTC enforcement action and material penalties and sanctions. 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, 2016, 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 2016 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 the Pennsylvania division does not have a rate case on file, see below for a description of the current 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 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.
On April 28, 2016, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by approximately $41.7 million. Distribution Corporation explained in the filing that its request for rate relief was necessitated by a revenue requirement driven primarily by rate base growth, higher operating expense and higher depreciation expense that are not reflected in current rates, among other things. The rate filing includes a proposal for system infrastructure modernization that includes the acceleration of Distribution Corporation's replacement of certain gas mains, which are of a type generically classified by the NYPSC as "leak prone pipe". After a full evidentiary hearing in early October 2016, on October 19, 2016, the Company filed a Notice of Impending Confidential Settlement Negotiations notifying the

NYPSC that Distribution Corporation, Department of Public Service Staff and other interested parties were entering into settlement discussions. On November 23, 2016, the Company filed a Notice of Discontinued Settlement Negotiations with the NYPSC advising that a settlement had not been reached and the parties were returning to the litigation schedule established in the case. On January 23, 2017, the administrative law judge assigned to the proceeding issued a recommended decision (RD) based on a review and assessment of the evidence presented in the case. The RD, as revised on January 26, 2017, recommends a rate increase designed to provide additional annual revenues of $8.5 million. The recommended equity ratio, subject to updates, is 42.3%, and is based on the Company's equity ratio, and the recommended cost of equity, subject to updates, is 8.6%. The NYPSC is not bound to accept the RD, and may accept, reject or modify Distribution Corporation's filing or the RD. Assuming standard procedure, rates would become effective in late April 2017. The outcome of the proceeding cannot be ascertained at this time.

Table of Contents

Pennsylvania Jurisdiction

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

Pipeline and Storage

Supply Corporation's current rate 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. Under the settlement, Supply Corporation reduced its maximum reservation, capacity, demand and deliverability rates by 2% on November 1, 2015 and reduced those rates by an additional 2% on November 1, 2016.
By order dated January 21, 2016, the FERC began a NGA Section 5 rate review of Empire's rates. As required by that order, Empire filed a Cost and Revenue Study on April 5, 2016. On May 25, 2016, Empire reached a settlement in principle on this matter that would, among other things, reduce certain of Empire’s maximum transportation rates over a 14-month period, which, based on current contracts, is estimated to reduce Empire’s revenues on a yearly basis by between $3 million to $4 million. The settlement also reduces Empire’s depreciation rate from 2.5% to 2%. In addition, the settlement provides an annual revenue sharing mechanism, pursuant to which non-expansion transportation revenues exceeding $73.5 million are shared on a tiered basis. Under the settlement, Empire will be required to make a general rate filing no later than July 1, 2021. On December 13, 2016, the FERC issued an order approving the settlement. The settlement is not expected to have a material impact on the Company’s financial condition.

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. Recently, the EPA adopted final regulations that set methane and volatile organic compound emissions standards for new or modified oil and gas emissions sources. These new rules impose more stringent leak detection and repair requirements, and 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. With respect to its operations in California, 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 aims to reduce greenhouse gas emissions could also include carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates to conserve energy or use renewable energy sources. Federal, state or local governments may, for example, provide tax advantages and other subsidies to support alternative energy sources, mandate the use of specific fuels or technologies, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources. These climate change and greenhouse gas initiatives 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. They could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, impose additional monitoring and reporting requirements, and 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.

Table of Contents

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-K 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. 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;
2. 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;
3. 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;
4. Impairments under the SEC’s full cost ceiling test for natural gas and oil reserves;
5. Changes in the price of natural gas or oil;
6. 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;
7. Factors affecting the Company’s ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with

environmental laws and regulations;

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

9. Changes in price differentials 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;

10. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;

Table of Contents

11. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
12. Uncertainty of oil and gas reserve estimates;
13. Significant differences between the Company's projected and actual production levels for natural gas or oil;
14. Changes in demographic patterns and weather conditions;
15. Changes in the availability, price or accounting treatment of derivative financial instruments;
16. 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;
17. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;
18. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;
19. Significant differences between the Company's projected and actual capital expenditures and operating expenses;
20. 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; or
21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that 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, 2016.

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, 2016 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

On August 19, 2016, the PaDEP sent a draft Consent Assessment of Civil Penalty (CACP) to Seneca, offering to settle various alleged violations of the Pennsylvania Oil and Gas Act, Clean Streams Law and Solid Waste Management Act, as well as PaDEP rules and regulations regarding erosion and sedimentation control relating to Seneca's drilling activities. The amount of the penalty sought by the PaDEP is not material to the Company. The draft CACP addresses alleged environmental and administrative violations identified by PaDEP during inspections of various sites and facilities in four counties over a two-year

Table of Contents

period. The Company disputes many of the alleged violations and will vigorously defend its position in negotiations with the PaDEP.

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 2016 Form 10-K have not materially changed other than as set forth below. The risk factor presented below supersedes the risk factor having the same caption in the 2016 Form 10-K and should otherwise be read in conjunction with all of the risk factors disclosed in the 2016 Form 10-K.

The Company’s need to comply with comprehensive, complex, and the sometimes unpredictable enforcement of government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

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

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

In addition to their historical methods of utility regulation, both the PaPUC and NYPSC have established competitive markets in which customers may purchase gas commodity from unregulated marketers, in addition to utility companies. Retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation because in both jurisdictions it recovers its cost of service through delivery rates and charges, and not through any mark-up on the gas commodity purchased by its customers. Over the longer run, however, rate design changes resulting from customer migration to marketer service ("unbundling") can expose utilities such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

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

would be adversely affected.
In New York, aggressive generic statewide programs created under the label of efficiency or conservation continue to generate a sizable utility funding requirement for state agencies that administer those programs. Although utilities are authorized to recover the cost of efficiency and conservation program funding through special rates and surcharges, the resulting upward pressure on customer rates, coupled with increased assessments and taxes, could affect future tolerance for traditional utility rate increases, especially if natural gas commodity costs were to increase.
The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries, including Seneca, Distribution Corporation and NFR. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their natural gas transportation and/or storage customers.

Table of Contents

Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. Pursuant to the petition of a customer or state commission, or on the FERC's own initiative, the FERC has the authority to investigate whether Supply Corporation's and Empire's rates are still "just and reasonable" as required by the NGA, and if not, to adjust those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to adjust the rates it charges its natural gas transportation and/or storage customers, or if either Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease. The FERC also possesses significant penalty authority with respect to violations of the laws and regulations it administers. Supply Corporation, Empire and, to the extent subject to FERC jurisdiction, the Company's other subsidiaries are subject to the FERC's penalty authority. In addition, the FERC exercises jurisdiction over the construction and operation of facilities used in interstate gas transmission. Also, decisions of Canadian regulators such as the National Energy Board and the Ontario Energy Board could affect the viability and profitability of Supply Corporation and Empire projects designed to transport gas from between Canada and the U.S.

The Company is also subject to the jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA issues regulations and conducts evaluations, among other things, that set safety standards for pipelines and underground storage facilities. Compliance with new legislation could increase costs to the Company. Non-compliance with this legislation could result in civil penalties for pipeline safety violations. If as a result of these or similar new laws or regulations the Company incurs material costs that it is unable to recover fully through rates or otherwise offset, the Company's financial condition, results of operations, and cash flows could be adversely affected.

In the Company 's Exploration and Production segment, various aspects of Seneca's operations are subject to regulation by, among others, the EPA, the U.S. Fish and Wildlife Service, the U.S. Forestry Service, the Bureau of Land Management, the PaDEP, the Pennsylvania Department of Conservation and Natural Resources, the Division of Oil, Gas and Geothermal Resources of the California Department of Conservation, the California Department of Fish and Wildlife, and in some areas, locally adopted ordinances. Administrative proceedings or increased regulation by these or other agencies could lead to operational delays or restrictions and increased expense for Seneca.

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

On October 3, 2016, the Company issued a total of 4,800 unregistered shares of Company common stock to eight non-employee directors of the Company then serving on the Board of Directors of the Company, 600 shares to each such director. On December 15, 2016, the Company issued 157 unregistered shares of Company common stock to Thomas E. Skains, who joined the Board on December 8, 2016 as a non-employee 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, 2016. 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, 2016	316	$54.43	—	6,971,019
Nov. 1 - 30, 2016	3,179	$54.27	—	6,971,019
	37,656	$57.55	—	6,971,019

Dec. 1 - 31, 2016				
Total	41,151	$57.27	—	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, 2016, 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.

Table of Contents

Item 6. Exhibits

Exhibit Number	Description of Exhibit
•	Form of Indemnification Agreement between National Fuel Gas Company and Thomas E. Skains, Director (Exhibit 10.1, Form 8-K dated September 18, 2006).
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, 2016 and the Fiscal Years Ended September 30, 2013 through 2016.
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, 2016 and 2015.
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, 2016 and 2015, (ii) the Consolidated Statements of Comprehensive Income for the three months ended December 31, 2016 and 2015, (iii) the Consolidated Balance Sheets at December 31, 2016 and September 30, 2016, (iv) the Consolidated Statements of Cash Flows for the three months ended December 31, 2016 and 2015 and (v) the Notes to Condensed Consolidated Financial Statements.

• Incorporated herein by reference as indicated.

•• 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.

Table of Contents

SIGNATURES

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

NATIONAL FUEL GAS COMPANY
(Registrant)

/s/ 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 3, 2017