NATIONAL FUEL GAS CO
Form 10-Q
August 04, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2017
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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer” “smaller reporting company,” and “emerging growth 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	¨
		Emerging Growth Company	¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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 July 31, 2017: 85,507,508 shares.

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GLOSSARY OF TERMS

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

National Fuel Gas Companies	
Company	The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
Midstream Corporation	National Fuel Gas Midstream Corporation
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
Seneca	Seneca Resources Corporation
Supply Corporation	National Fuel Gas Supply Corporation

Regulatory Agencies	
CFTC	Commodity Futures Trading Commission
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
NYDEC	New York State Department of Environmental Conservation
NYPSC	State of New York Public Service Commission
PaDEP	Pennsylvania Department of Environmental Protection
PaPUC	Pennsylvania Public Utility Commission
SEC	Securities and Exchange Commission

Other	
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 (e.g. a marketer) pays for gas the customer receives in excess of amounts delivered into pipeline/storage or distribution 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
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act.

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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.
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.

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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.

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• The Company has nothing to report under this item.

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

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Part I. Financial Information

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
(Thousands of Dollars, Except Per Common Share Amounts)	2017	2016	2017	2016
INCOME				
Operating Revenues:				
Utility and Energy Marketing Revenues	$146,360	$123,976	$663,029	$540,981
Exploration and Production and Other Revenues	151,925	158,578	473,617	456,032
Pipeline and Storage and Gathering Revenues	50,083	53,063	156,298	162,930
	348,368	335,617	1,292,944	1,159,943
Operating Expenses:				
Purchased Gas	46,135	23,477	264,349	147,168
Operation and Maintenance:				
Utility and Energy Marketing	44,467	46,616	158,796	151,474
Exploration and Production and Other	34,098	35,427	102,153	123,965
Pipeline and Storage and Gathering	23,250	23,215	69,016	64,324
Property, Franchise and Other Taxes	21,447	20,261	64,368	61,923
Depreciation, Depletion and Amortization	55,617	58,802	168,812	193,300
Impairment of Oil and Gas Producing Properties	—	82,658	—	915,552
	225,014	290,456	827,494	1,657,706
Operating Income (Loss)	123,354	45,161	465,450	(497,763)
Other Income (Expense):				
Interest Income	853	564	2,844	2,640
Other Income	1,370	1,519	4,728	7,173
Interest Expense on Long-Term Debt	(29,225)	(28,897)	(87,241)	(88,263)
Other Interest Expense	(846)	(1,321)	(2,680)	(3,938)
Income (Loss) Before Income Taxes	95,506	17,026	383,101	(580,151)
Income Tax Expense (Benefit)	35,792	8,740	145,195	(251,641)
Net Income (Loss) Available for Common Stock	59,714	8,286	237,906	(328,510)
EARNINGS REINVESTED IN THE BUSINESS				
Balance at Beginning of Period	817,348	699,399	676,361	1,103,200
	877,062	707,685	914,267	774,690
Dividends on Common Stock	(35,469)	(34,404)	(104,590)	(101,409)
Cumulative Effect of Adoption of Authoritative Guidance for Stock-Based Compensation	—	—	31,916	—
Balance at June 30	$841,593	$673,281	$841,593	$673,281

Earnings Per Common Share:

Basic:				
Net Income (Loss) Available for Common Stock	$0.70	$0.10	$2.79	$(3.87)
Diluted:				
Net Income (Loss) Available for Common Stock	$0.69	$0.10	$2.77	$(3.87)
Weighted Average Common Shares Outstanding:				
Used in Basic Calculation	85,422,313	84,917,664	85,315,154	84,791,447
Used in Diluted Calculation	86,064,464	85,470,216	85,950,742	84,791,447
Dividends Per Common Share:				
Dividends Declared	$0.415	$0.405	$1.225	$1.195

See Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended June 30,		Nine Months Ended June 30,	
(Thousands of Dollars)	2017	2016	2017	2016
Net Income (Loss) Available for Common Stock	$59,714	$8,286	$237,906	$(328,510)
Other Comprehensive Income (Loss), Before Tax:				
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	1,437	376	2,280	(266)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	18,233	(70,363)	9,829	28,777
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	—	—	(741)	(388)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(18,452)	(58,373)	(59,641)	(176,779)
Other Comprehensive Income (Loss), Before Tax	1,218	(128,360)	(48,273)	(148,656)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	532	122	832	(85)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	7,592	(29,521)	3,892	5,345
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	—	—	(272)	(163)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(7,693)	(24,514)	(25,061)	(68,120)
Income Taxes – Net	431	(53,913)	(20,609)	(63,023)
Other Comprehensive Income (Loss)	787	(74,447)	(27,664)	(85,633)
Comprehensive Income (Loss)	$60,501	$(66,161)	$210,242	$(414,143)

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2017	September 30, 2016
ASSETS		
Property, Plant and Equipment	$9,816,295	$ 9,539,581
Less - Accumulated Depreciation, Depletion and Amortization	5,232,771	5,085,099
	4,583,524	4,454,482
Current Assets		
Cash and Temporary Cash Investments	285,325	129,972
Hedging Collateral Deposits	2,142	1,484
Receivables – Net of Allowance for Uncollectible Accounts of $27,545 and $21,109, Respectively	127,876	133,201
Unbilled Revenue	19,729	18,382
Gas Stored Underground	17,793	34,332
Materials and Supplies - at average cost	34,706	33,866
Unrecovered Purchased Gas Costs	3,757	2,440
Other Current Assets	50,852	59,354
	542,180	413,031
Other Assets		
Recoverable Future Taxes	182,469	177,261
Unamortized Debt Expense	1,292	1,688
Other Regulatory Assets	315,126	320,750
Deferred Charges	28,821	20,978
Other Investments	126,485	110,664
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	18,619	17,649
Fair Value of Derivative Financial Instruments	63,036	113,804
Other	479	604
	741,803	768,874
Total Assets	$5,867,507	$ 5,636,387

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	June 30, 2017	September 30, 2016
(Thousands of Dollars)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 85,467,963 Shares and 85,118,886 Shares, Respectively	$85,468	$85,119
Paid in Capital	790,291	771,164
Earnings Reinvested in the Business	841,593	676,361
Accumulated Other Comprehensive Loss	(33,304)	(5,640)
Total Comprehensive Shareholders' Equity	1,684,048	1,527,004
Long-Term Debt, Net of Unamortized Discount and Debt Issuance Costs	1,787,954	2,086,252
Total Capitalization	3,472,002	3,613,256
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	300,000	—
Accounts Payable	98,842	108,056
Amounts Payable to Customers	13,070	19,537
Dividends Payable	35,469	34,473
Interest Payable on Long-Term Debt	28,985	34,900
Customer Advances	224	14,762
Customer Security Deposits	17,522	16,019
Other Accruals and Current Liabilities	107,101	74,430
Fair Value of Derivative Financial Instruments	922	1,560
	602,135	303,737
Deferred Credits		
Deferred Income Taxes	881,547	823,795
Taxes Refundable to Customers	93,321	93,318
Cost of Removal Regulatory Liability	199,739	193,424
Other Regulatory Liabilities	88,647	99,789
Pension and Other Post-Retirement Liabilities	299,326	277,113
Asset Retirement Obligations	115,354	112,330
Other Deferred Credits	115,436	119,625
	1,793,370	1,719,394
Commitments and Contingencies (Note 6)	—	—
Total Capitalization and Liabilities	$5,867,507	$5,636,387

See Notes to Condensed Consolidated Financial Statements

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

(Thousands of Dollars)	Nine Months Ended June 30, 2017	2016
OPERATING ACTIVITIES		
Net Income (Loss) Available for Common Stock	$237,906	$(328,510)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:		
Impairment of Oil and Gas Producing Properties	—	915,552
Depreciation, Depletion and Amortization	168,812	193,300
Deferred Income Taxes	105,073	(269,248)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	—	(1,786)
Stock-Based Compensation	8,857	3,138
Other	11,084	9,685
Change in:		
Hedging Collateral Deposits	(658)	8,116
Receivables and Unbilled Revenue	(15,885)	(7,756)
Gas Stored Underground and Materials and Supplies	15,699	15,683
Unrecovered Purchased Gas Costs	(1,317)	(933)
Other Current Assets	8,502	15,334
Accounts Payable	5,046	(53,687)
Amounts Payable to Customers	(6,467)	(21,337)
Customer Advances	(14,538)	(16,198)
Customer Security Deposits	1,503	(396)
Other Accruals and Current Liabilities	25,423	3,375
Other Assets	(3,548)	3,775
Other Liabilities	5,638	(8,152)
Net Cash Provided by Operating Activities	551,130	459,955
INVESTING ACTIVITIES		
Capital Expenditures	(314,774)	(481,781)
Net Proceeds from Sale of Oil and Gas Producing Properties	26,554	115,235
Other	(10,186)	(11,163)
Net Cash Used in Investing Activities	(298,406)	(377,709)
FINANCING ACTIVITIES		
Excess Tax Benefits Associated with Stock-Based Compensation Awards	—	1,786
Dividends Paid on Common Stock	(103,594)	(100,419)
Net Proceeds from Issuance of Common Stock	6,223	8,358
Net Cash Used in Financing Activities	(97,371)	(90,275)
Net Increase (Decrease) in Cash and Temporary Cash Investments	155,353	(8,029)
Cash and Temporary Cash Investments at October 1	129,972	113,596
Cash and Temporary Cash Investments at June 30	$285,325	$105,567
Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		

Non-Cash Capital Expenditures	$47,508	$44,380
Receivable from Sale of Oil and Gas Producing Properties	$—	$22,081

See Notes to Condensed Consolidated Financial Statements

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.

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

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments (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 nine months ended June 30, 2017 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 $7.7 million at June 30, 2017, 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 $100.6 million and $135.3 million at June 30, 2017 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

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under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. At June 30, 2017, the ceiling exceeded the book value of the oil and gas properties by approximately $304.8 million. In adjusting estimated future cash flows for hedging under the ceiling test at June 30, 2017, estimated future net cash flows were increased by $49.8 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. 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. Of this amount, IOG has funded $262.5 million as of June 30, 2017, which includes $163.9 million of cash ($137.3 million in fiscal 2016 and $26.6 million in fiscal 2017) that Seneca had received 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 were recorded by Seneca as a $163.9 million reduction of property, plant and equipment. The remainder funded joint development expenditures. 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.

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Accumulated Other Comprehensive Income (Loss). The components of Accumulated Other Comprehensive Income (Loss) and changes for the nine months ended June 30, 2017 and 2016, 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 June 30, 2017				
Balance at April 1, 2017	$ 36,257	$ 6,128	$ (76,476)	$ (34,091)
Other Comprehensive Gains and Losses Before Reclassifications	10,641	905	—	11,546
Amounts Reclassified From Other Comprehensive Income (Loss)	(10,759)	—	—	(10,759)
Balance at June 30, 2017	$ 36,139	$ 7,033	$ (76,476)	$ (33,304)
Nine Months Ended June 30, 2017				
Balance at October 1, 2016	$ 64,782	$ 6,054	$ (76,476)	$ (5,640)
Other Comprehensive Gains and Losses Before Reclassifications	5,937	1,448	—	7,385
Amounts Reclassified From Other Comprehensive Income (Loss)	(34,580)	(469)	—	(35,049)
Balance at June 30, 2017	$ 36,139	$ 7,033	$ (76,476)	$ (33,304)
Three Months Ended June 30, 2016				
Balance at April 1, 2016	$ 146,671	$ 5,309	$ (69,794)	$ 82,186
Other Comprehensive Gains and Losses Before Reclassifications	(40,842)	254	—	(40,588)
Amounts Reclassified From Other Comprehensive Income (Loss)	(33,859)	—	—	(33,859)
Balance at June 30, 2016	$ 71,970	$ 5,563	$ (69,794)	$ 7,739
Nine Months Ended June 30, 2016				
Balance at October 1, 2015	$ 157,197	$ 5,969	$ (69,794)	$ 93,372
Other Comprehensive Gains and Losses Before Reclassifications	23,432	(181)	—	23,251
Amounts Reclassified From Other Comprehensive Income (Loss)	(108,659)	(225)	—	(108,884)
Balance at June 30, 2016	$ 71,970	$ 5,563	$ (69,794)	$ 7,739

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Reclassifications Out of Accumulated Other Comprehensive Income (Loss). The details about the reclassification adjustments out of accumulated other comprehensive loss for the nine months ended June 30, 2017 and 2016 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Income (Loss) Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss)				Affected Line Item in the Statement Where Net Income (Loss) is Presented
	Three Months Ended June 30,		Nine Months Ended June 30,		
	2017	2016	2017	2016	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:					
Commodity Contracts	$18,600	$58,354	$62,030	$172,596	Operating Revenues
Commodity Contracts	21	70	(1,938)	4,520	Purchased Gas
Foreign Currency Contracts	(169)	(51)	(451)	(337)	Operation and Maintenance Expense
Gains (Losses) on Securities Available for Sale	—	—	741	388	Other Income
	18,452	58,373	60,382	177,167	Total Before Income Tax
	(7,693)	(24,514)	(25,333)	(68,283)	Income Tax Expense
	$10,759	$33,859	$35,049	$108,884	Net of Tax

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

	At June 30, 2017	At September 30, 2016
Prepayments	$11,396	$ 10,919
Prepaid Property and Other Taxes	11,180	13,138
Federal Income Taxes Receivable	—	11,758
State Income Taxes Receivable	9,658	3,961
Fair Values of Firm Commitments	1,473	3,962
Regulatory Assets	17,145	15,616
	$50,852	$ 59,354

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

	At June 30, 2017	At September 30, 2016
Accrued Capital Expenditures	$28,129	$ 26,796
Regulatory Liabilities	34,552	14,725
Reserve for Gas Replacement	7,667	—
Federal Income Taxes Payable	2,573	—
Other	34,180	32,909
	$107,101	$ 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 and nine months ended June 30, 2017, 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 172,500 securities and 157,638 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2017, respectively. There were 346,090

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securities excluded as being antidilutive for the quarter ended June 30, 2016. As the Company recognized a net loss for the nine months ended June 30, 2016, the aforementioned potentially dilutive securities, amounting to 414,092 securities, were not recognized in the diluted earnings per share calculation for the nine months ended June 30, 2016.

Stock-Based Compensation. The Company granted 184,148 performance shares during the nine months ended June 30, 2017. The weighted average fair value of such performance shares was $56.39 per share for the nine months ended June 30, 2017. 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 nine months ended June 30, 2017 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 nine months ended June 30, 2017 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 87,143 non-performance based restricted stock units during the nine months ended June 30, 2017. The weighted average fair value of such non-performance based restricted stock units was $52.13 per share for the nine months ended June 30, 2017. 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.

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. Recent task force guidance suggests that the Company's revenue recognition policies may not change significantly although the Company is still assessing the impact. The Company will need to enhance its financial statement disclosures to comply with the new authoritative guidance.

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 March 2017, the FASB issued authoritative guidance related to the presentation of net periodic pension cost and net periodic postretirement benefit cost. The new guidance requires segregation of the service cost component from the other components of net periodic pension cost and net periodic postretirement benefit cost for financial reporting purposes. The service cost component is to be presented on the income statement in the same line items as other compensation costs included within Operating Expenses and the other components of net periodic pension cost and net periodic postretirement benefit cost are to be presented on the income statement below the subtotal labeled Operating Income (Loss). Under this guidance, the service cost component shall be the only component eligible to be capitalized as part of the cost of inventory or property, plant and equipment. The new guidance will be effective as of the Company's first quarter of fiscal 2019, with early adoption permitted. The Company is currently evaluating the interaction of this authoritative guidance with the various regulatory provisions concerning pension and postretirement benefit costs in the Company's Utility and Pipeline and Storage segments.

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.

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The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of June 30, 2017 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 June 30, 2017				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$257,721	$—	$ —	$ —	$257,721
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	1,354	—	—	(1,125)	229
Over the Counter Swaps – Gas and Oil	—	67,890	—	(3,895)	63,995
Foreign Currency Contracts	—	336	—	(1,524)	(1,188)
Other Investments:					
Balanced Equity Mutual Fund	36,107	—	—	—	36,107
Fixed Income Mutual Fund	45,547	—	—	—	45,547
Common Stock – Financial Services Industry	3,859	—	—	—	3,859
Hedging Collateral Deposits	2,142	—	—	—	2,142
Total	$346,730	$68,226	$ —	$ (6,544)	$408,412
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$1,125	$—	$ —	$ (1,125)	$—
Over the Counter Swaps – Gas and Oil	—	4,817	—	(3,895)	922
Foreign Currency Contracts	—	1,524	—	(1,524)	—
Total	$1,125	$6,341	$ —	$ (6,544)	$922
Total Net Assets/(Liabilities)	$345,605	$61,885	$ —	$ —	$407,490

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.

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Derivative Financial Instruments

At June 30, 2017 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. Hedging collateral deposits were $2.1 million at June 30, 2017 and $1.5 million at September 30, 2016, 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 June 30, 2017 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 June 30, 2017 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 June 30, 2017, 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 the nine months ended June 30, 2017, 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 during the first quarter of fiscal 2016. For the quarters and nine months ended June 30, 2017 and June 30, 2016, no transfers in or out of Level 1 or Level 2 occurred.

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):

	June 30, 2017		September 30, 2016	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$2,087,954	$2,220,588	$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 $41.0 million at June 30, 2017 and $39.7 million at September 30, 2016. The fair value of the equity mutual fund was $36.1 million at June 30, 2017 and $36.7 million at September 30, 2016. The gross unrealized gain on this equity mutual

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fund was $8.6 million at June 30, 2017 and $7.9 million at September 30, 2016. The fair value of the fixed income mutual fund was $45.5 million at June 30, 2017 and $31.4 million at September 30, 2016. The gross unrealized loss on this fixed income mutual fund was less than $0.1 million at June 30, 2017 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 $3.9 million at June 30, 2017 and $2.9 million at September 30, 2016. The gross unrealized gain on this stock was $2.6 million at June 30, 2017 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 7 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 Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at June 30, 2017 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 June 30, 2017, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	126.6	Bcf (short positions)
Natural Gas	1.1	Bcf (long positions)
Crude Oil	2,631,000	Bbls (short positions)

As of June 30, 2017, the Company was hedging a total of $88.2 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts (long positions).
As of June 30, 2017, the Company had $62.0 million ($36.1 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $39.3 million ($22.9 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.

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended June 30, 2017 and 2016 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Three Months Ended June 30,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Three Months Ended June 30,		Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Three Months Ended June 30,	
	2017	2016		2017	2016		2017	2016
Commodity Contracts	$17,342	$(68,914)	Operating Revenue	$18,600	$58,354	Operating Revenue	$ 1,040	$ 87
Commodity Contracts	240	(921)	Purchased Gas	21	70	Not Applicable	—	—
Foreign Currency Contracts	651	(528)	Operation and Maintenance Expense	(169)	(51)	Not Applicable	—	—
Total	$18,233	$(70,363)		$18,452	$58,373		$ 1,040	$ 87

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2017 and 2016 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Nine Months Ended June 30,	Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Nine Months Ended June 30,	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Nine

							Months Ended June 30,	
	2017	2016		2017	2016		2017	2016
Commodity Contracts	$9,382	$27,304	Operating Revenue	$62,030	$172,596	Operating Revenue	$ 940	$ 255
Commodity Contracts	(252)	1,078	Purchased Gas	(1,938)	4,520	Not Applicable	—	—
Foreign Currency Contracts	699	395	Operation and Maintenance Expense	(451)	(337)	Not Applicable	—	—
Total	$9,829	$28,777		$59,641	$176,779		$ 940	$ 255

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 net realizable value writedown of the value of natural gas in storage that is recorded in the Company’s financial statements. As of June 30, 2017, the Company’s Energy Marketing segment had fair value hedges covering approximately 17.0 Bcf (16.0 Bcf of fixed price sales commitments, 0.1 Bcf of fixed price purchase commitments and 0.9 Bcf of commitments related to the withdrawal of storage gas). For derivative instruments that are

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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 Nine Months Ended June 30, 2017 (In Thousands)	Amount of Gain or (Loss) on the Hedged Item Recognized in the Consolidated Statement of Income for the Nine Months Ended June 30, 2017 (In Thousands)
Commodity Contracts	Operating Revenues	$ 1,317	$ (1,317)
Commodity Contracts	Purchased Gas	$ 427	$ (427)
		$ 1,744	$ (1,744)

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 all sixteen are in a net gain position. On average, the Company had $3.9 million of credit exposure per counterparty in a gain position at June 30, 2017. The maximum credit exposure per counterparty in a gain position at June 30, 2017 was $8.9 million. As of June 30, 2017, 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 June 30, 2017, 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 June 30, 2017, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $42.5 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 June 30, 2017.

For its exchange traded futures contracts, the Company was required to post $2.1 million in hedging collateral deposits as of June 30, 2017. 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.

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Note 4 - Income Taxes

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

	Nine Months Ended June 30,	
	2017	2016
Current Income Taxes		
Federal	$29,832	$(686)
State	10,290	18,293
Deferred Income Taxes		
Federal	81,163	(184,419)
State	23,910	(84,829)
	145,195	(251,641)
Deferred Investment Tax Credit	(130)	(261)
Total Income Taxes	$145,065	$(251,902)
Presented as Follows:		
Other Income	(130)	(261)
Income Tax Expense (Benefit)	145,195	(251,641)
Total Income Taxes	$145,065	$(251,902)

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):

	Nine Months Ended June 30,	
	2017	2016
U.S. Income (Loss) Before Income Taxes	$382,971	$(580,412)
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate of 35%	$134,040	$(203,144)
State Income Taxes (Benefit)	22,230	(43,248)
Miscellaneous	(11,205)	(5,510)
Total Income Taxes	$145,065	$(251,902)

Note 5 - Capitalization

Common Stock. During the nine months ended June 30, 2017, the Company issued 31,632 original issue shares of common stock as a result of stock option and SARs exercises, 79,530 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 146,872 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 78,327 original issue shares of common stock for the Company’s 401(k) plans. The Company also issued 17,017 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 nine months ended June 30, 2017. 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 nine months ended June 30, 2017, 47,785 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.

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Current Portion of Long-Term Debt. Current portion of Long-Term Debt at June 30, 2017 consists of $300.0 million of 6.50% notes that mature in April 2018.

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 June 30, 2017, 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 $3.2 million. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 4 years.

The Company's estimated liability for clean-up costs discussed above includes a $1.8 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 complete. The Company continues to be responsible for future ongoing monitoring and long-term maintenance at the site.

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.

Northern Access 2016 Project. On February 3, 2017, Supply Corporation and Empire received FERC approval of the Northern Access 2016 project described herein. On April 7, 2017, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received on January 27, 2017). On April 21, 2017, Supply Corporation and Empire filed a Petition for Review in the United States Court of Appeals for the Second Circuit of the NYDEC's Notice of Denial with respect to National Fuel's application for the Water Quality Certification, and on May 11, 2017, the Company commenced legal action in New York State Supreme Court challenging the NYDEC's actions with regard to various state permits. In light of the pending legal action, the Company has not yet determined a revised target in-service date. As a result of the decision of the NYDEC, Supply Corporation and Empire evaluated the capitalized project costs for impairment as of June 30, 2017 and determined that an impairment charge was not required. The evaluation considered probability weighted scenarios of undiscounted future net cash flows, including a scenario assuming successful resolution with the NYDEC and construction of the pipeline, as well as a scenario where the project does not proceed. Further developments or indicators of an unfavorable resolution could result in the impairment of a significant portion of the project costs, which totaled $73.7 million at June 30, 2017. The project costs are included within Property, Plant and Equipment and Deferred Charges on the Consolidated Balance Sheet.

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

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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 June 30, 2017 and September 30, 2016 is shown in the tables below.

Quarter Ended June 30, 2017 (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	$151,161	$50,049	$34	$121,900	$24,460	$347,604	$538	$226	$348,368
Intersegment Revenues	$—	$21,643	$26,853	$3,391	$565	$52,452	$—	$(52,452)	$—
Segment Profit: Net Income (Loss)	$30,123	$16,031	$10,107	$4,348	$(564)	$60,045	$(98)	$(233)	$59,714

Nine Months Ended June 30, 2017 (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	$471,646	$156,212	$86	$550,819	$112,210	$1,290,973	$1,311	$660	$1,292,944
Intersegment Revenues	$—	$66,389	$82,629	$11,314	$600	$160,932	$—	$(160,932)	$—
Segment Profit: Net Income (Loss)	$98,972	$54,656	$31,373	$51,103	$2,122	$238,226	$(498)	$178	$237,906

(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 June 30, 2017	$1,394,320	$1,732,632	$568,115	$2,078,688	$67,613	$5,841,368	$76,560	$(50,421)	$5,867,507
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 June 30, 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	$156,835	$52,998	$65	$106,568	$17,408	$333,874	$1,508	$235	$335,617

Intersegment Revenues	$—	$22,795	$25,417	$1,729	$231	$50,172	$—	$(50,172)	$—
Segment Profit: Net Income (Loss)	$(19,165)	$17,323	$9,473	$2,179	$(590)	$9,220	$430	$(1,364)	$8,286

Nine Months Ended June 30, 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	$452,583	$162,627	$303	$463,154	$77,827	$1,156,494	$2,775	$674	$1,159,943
Intersegment Revenues	$—	$68,272	$65,601	$10,757	$855	$145,485	$—	$(145,485)	$—
Segment Profit: Net Income (Loss)	$(469,586)	$59,794	$21,962	$52,745	$4,117	$(330,968)	$595	$1,863	$(328,510)

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Note 8 – Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

Three Months Ended June 30,	Retirement Plan 2017	Retirement Plan 2016	Other Post-Retirement Benefits 2017	Other Post-Retirement Benefits 2016
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]	(3,193)	14	1,302	3,936
Net Periodic Benefit Cost	$5,402	$7,049	$3,298	$2,886

Nine Months Ended June 30,	Retirement Plan 2017	Retirement Plan 2016	Other Post-Retirement Benefits 2017	Other Post-Retirement Benefits 2016
Service Cost	$8,977	$8,783	$1,837	$1,748
Interest Cost	28,788	31,736	14,256	15,289
Expected Return on Plan Assets	(44,788)	(44,527)	(23,594)	(23,651)
Amortization of Prior Service Cost (Credit)	793	925	(322)	(684)
Amortization of Losses	32,015	24,186	13,811	4,147
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	3,577	7,531	6,404	14,657
Net Periodic Benefit Cost	$29,362	$28,634	$12,392	$11,506

(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 nine months ended June 30, 2017, the Company contributed $15.1 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $3.2 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2017, the Company may contribute up to $5.0 million to the Retirement Plan. In the remainder of 2017, the Company expects to contribute approximately $0.5 million to its VEBA trusts and 401(h) accounts.

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, among other things. On January 23, 2017, the administrative law judge assigned to the proceeding issued a recommended decision (RD) in the case. The RD, as revised on January 26, 2017, recommended a rate increase designed to provide additional annual revenues of $8.5 million, an equity ratio, subject to update of 42.3% based on the Company's equity ratio, and a cost of equity, subject to update of 8.6%. On April 20, 2017, the NYPSC issued an Order adopting some provisions of the RD and modifying or rejecting others. The Order provides for an annual rate increase of $5.9 million. The rate increase became effective May 1, 2017. The Order further provides for a return on equity of 8.7%, and established an equity ratio of 42.9%. The Order also directs the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018, only if the Company does not file for new rates to become effective on or before October 1, 2018.

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On July 28, 2017, Distribution Corporation filed an appeal with New York State Supreme Court, Albany County, seeking review of the rate order. The appeal contends that portions of the rate order should be invalidated because they fail to meet the applicable legal standard for agency decisions. The Company cannot predict the outcome of the appeal at this time.

FERC Rate Proceedings

Supply Corporation currently has no active rate case on file. 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.

Empire currently has no active rate case on file. Empire’s current rate settlement requires a rate case filing no later than July 1, 2021.

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 and nine months ended June 30, 2017 compared to the quarter and nine months ended June 30, 2016, the Company experienced increases in earnings of $51.4 million and $566.4 million, respectively, primarily due to higher earnings in the Exploration and Production segment. During the quarter and nine months ended June 30, 2016, the Company recorded impairment charges of $82.7 million ($47.9 million after-tax) and $915.6 million ($531.0 million after-tax) that did not recur during the quarter and nine months ended June 30, 2017. 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, March 31, 2016 and June 30, 2016, 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 charges 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.

On February 3, 2017, the Company, in its Pipeline and Storage segment, received FERC approval of a 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”). On April 7, 2017, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received on January 27, 2017). The Company remains committed to the project. On April 21, 2017, the Company appealed the NYDEC's decision with regard to the Water Quality Certification to the United States Court of Appeals for the Second Circuit, and on May 11, 2017, the Company commenced legal action in New York State Supreme Court challenging the NYDEC's actions with regard to various state permits. Approximately $73.7 million in costs have been incurred on this project through June 30, 2017, with the costs residing either in Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet, or Deferred Charges. Seneca has two downstream Canadian transportation contracts to move incremental volumes associated with the Northern Access 2016 project. One of the contracts has a term expiring on March 31, 2023 with a remaining commitment of approximately $26.3 million (using a 1.2965 Exchange Rate). The other transportation precedent agreement was suspended until the Northern Access 2016 project has received all its necessary permits. Seneca will pay $2.4 million associated with this suspension during the quarter ended September 30, 2017 and will be reimbursed this amount if the project is reinstated. As noted above, the Company

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remains committed to the Northern Access 2016 project. Seneca has mitigated a portion of the current capacity costs through capacity release arrangements.

From a financing perspective, the Company expects to use cash on hand and cash from operations to meet its capital expenditure needs for fiscal 2017. The Company does not anticipate additional impairments of its oil and gas properties during the remainder of fiscal 2017 and expects to be able to issue additional long-term unsecured indebtedness as needed.

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 June 30, 2017, the ceiling exceeded the book value of the oil and gas properties by approximately $304.8 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended June 30, 2017, based on posted Midway Sunset prices, was $43.36 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 June 30, 2017, based on the quoted Henry Hub spot price for natural gas, was $3.01 per MMBtu. (Note – because actual pricing of the Company’s various producing properties varies depending on their location and hedging, the prices used to calculate the ceiling may differ from the Midway Sunset and Henry Hub prices, which are only indicative of the 12-month average prices for the twelve months ended June 30, 2017. Pricing differences would include adjustments for regional market differentials, transportation fees and contractual arrangements.) The following table illustrates the sensitivity of the ceiling test calculation to commodity price changes, specifically showing the amounts the ceiling would have exceeded the book value of the Company's oil and gas properties at June 30, 2017 (which would not have resulted in an impairment charge) if natural gas prices were $0.25 per MMBtu lower than the average prices used at June 30, 2017, if crude oil prices were $5 per Bbl lower than the average prices used at June 30, 2017, and 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 June 30, 2017 (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

Excess of Ceiling over Book Value under Sensitivity Analysis	$ 186.4	$ 269.0	$ 150.7

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, increases in development costs for undeveloped 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.

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RESULTS OF OPERATIONS

Earnings

The Company's earnings were $59.7 million for the quarter ended June 30, 2017 compared to earnings of $8.3 million for the quarter ended June 30, 2016. The increase in earnings of $51.4 million is primarily a result of higher earnings in the Exploration and Production segment, Utility segment and Gathering segment, as well as a lower loss in the Corporate category. Lower earnings in the Pipeline and Storage segment and a loss in the All Other category partially offset these increases.

The Company's earnings were $237.9 million for the nine months ended June 30, 2017 compared to a loss of $328.5 million for the nine months ended June 30, 2016. The increase in earnings of $566.4 million is primarily a result of higher earnings in the Exploration and Production segment and Gathering segment. Lower earnings in the Pipeline and Storage segment, Utility segment, Energy Marketing segment and Corporate category, as well as a loss in the All Other category, partially offset these increases.

The Company's earnings for the quarter and nine months ended June 30, 2016 include non-cash impairment charges of $82.7 million ($47.9 million after-tax) and $915.6 million ($531.0 million after-tax), respectively, recorded during the quarter and nine months ended June 30, 2016 for the Exploration and Production segment's oil and gas producing properties, as discussed above. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

(Thousands)	Three Months Ended June 30, 2017	2016	Increase (Decrease)	Nine Months Ended June 30, 2017	2016	Increase (Decrease)
Exploration and Production	$30,123	$(19,165)	$ 49,288	$98,972	$(469,586)	$568,558
Pipeline and Storage	16,031	17,323	(1,292)	54,656	59,794	(5,138)
Gathering	10,107	9,473	634	31,373	21,962	9,411
Utility	4,348	2,179	2,169	51,103	52,745	(1,642)
Energy Marketing	(564)	(590)	26	2,122	4,117	(1,995)
Total Reportable Segments	60,045	9,220	50,825	238,226	(330,968)	569,194
All Other	(98)	430	(528)	(498)	595	(1,093)
Corporate	(233)	(1,364)	1,131	178	1,863	(1,685)
Total Consolidated	$59,714	$8,286	$ 51,428	$237,906	$(328,510)	$566,416

Exploration and Production

Exploration and Production Operating Revenues

(Thousands)	Three Months Ended June 30, 2017	2016	Increase (Decrease)	Nine Months Ended June 30, 2017	2016	Increase (Decrease)
Gas (after Hedging)	$113,776	$113,125	$ 651	$357,158	$323,655	$ 33,503
Oil (after Hedging)	35,504	42,797	(7,293)	110,620	125,831	(15,211)

Gas Processing Plant	704	576	128	2,393	1,849	544
Other	1,177	337	840	1,475	1,248	227
	$151,161	$156,835	$ (5,674)	$471,646	$452,583	$ 19,063

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Production Volumes

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2017	2016	Increase (Decrease)	2017	2016	Increase (Decrease)
Gas Production (MMcf)						
Appalachia	37,904	38,846	(942)	118,517	105,747	12,770
West Coast	733	763	(30)	2,246	2,310	(64)
Total Production	38,637	39,609	(972)	120,763	108,057	12,706
Oil Production (Mbbl)						
Appalachia	1	6	(5)	3	16	(13)
West Coast	669	722	(53)	2,062	2,183	(121)
Total Production	670	728	(58)	2,065	2,199	(134)

Average Prices

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2017	2016	Increase (Decrease)	2017	2016	Increase (Decrease)
Average Gas Price/Mcf						
Appalachia	$2.58	$1.73	$ 0.85	$2.55	$1.84	$ 0.71
West Coast	$3.39	$2.84	$ 0.55	$4.07	$3.13	$ 0.94
Weighted Average	$2.59	$1.75	$ 0.84	$2.58	$1.87	$ 0.71
Weighted Average After Hedging	$2.94	$2.86	$ 0.08	$2.96	$3.00	$ (0.04)
Average Oil Price/Bbl						
Appalachia	$48.34	$58.28	$ (9.94)	$48.85	$44.05	$ 4.80
West Coast	$45.63	$38.89	$ 6.74	$45.71	$34.02	$ 11.69
Weighted Average	$45.64	$39.04	$ 6.60	$45.76	$34.10	$ 11.66
Weighted Average After Hedging	$53.02	$58.79	$ (5.77)	$53.58	$57.22	$ (3.64)

2017 Compared with 2016

Operating revenues for the Exploration and Production segment decreased $5.7 million for the quarter ended June 30, 2017 as compared with the quarter ended June 30, 2016. Oil production revenue after hedging decreased $7.3 million due to a decrease in crude oil production (due to changes in steam operations and a reduction in well workover activity at its North Midway Sunset field) coupled with a $5.77 per Bbl decrease in the weighted average price of oil after hedging. This was partially offset by the impact of gas production revenue after hedging increasing $0.7 million. The impact of a $0.08 per Mcf increase in the weighted average price of gas after hedging was partially offset by a slight decrease in gas production (due mainly to a lower net revenue interest on new wells connected to sales in the Western Development Area over the last twelve months, as a result of the joint development agreement with IOG, as well as natural declines in Marcellus production from the Eastern Development Area). In addition, mark-to-market adjustments related to hedging ineffectiveness (a component of Other Revenue) that occurred during the quarter ended June 30, 2017 increased revenues by $1.0 million.

Operating revenues for the Exploration and Production segment increased $19.1 million for the nine months ended June 30, 2017 as compared with the nine months ended June 30, 2016. Gas production revenue after hedging increased $33.5 million primarily due to a large increase in gas production (production curtailments experienced in fiscal 2016 did not recur in fiscal 2017 due to an improved pricing outlook) partially offset by a $0.04 per Mcf decrease in the weighted average price of gas after hedging. In addition, mark-to-market adjustments related to hedging ineffectiveness (a component of Other Revenue) that occurred during the quarter ended June 30, 2017 increased revenues by $1.0 million. The increases were partially offset by a decrease in oil production revenue after hedging of $15.2 million due to a decrease in crude oil production (due to changes in steam operations and a reduction in well workover activity at its North Midway Sunset field) coupled with a $3.64 per Bbl decrease in the weighted average price of oil after hedging.

The Exploration and Production segment's earnings for the quarter ended June 30, 2017 were $30.1 million compared with a loss of $19.2 million for the quarter ended June 30, 2016. The increase in earnings primarily reflects the non-recurrence of the aforementioned impairment charge ($47.9 million). It also reflects higher natural gas prices after hedging ($2.2 million), lower depletion expense ($2.5 million), the impact of the aforementioned mark-to-market adjustments ($0.6 million), the non-recurrence of joint development agreement professional fees ($1.8 million) and lower income tax expense ($2.4 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. The decrease in income tax expense is largely due to an enhanced oil recovery tax credit related to Seneca's California properties, which was applicable this year as a result of relatively low domestic crude oil prices. The joint development agreement professional fees incurred were related to professional services associated with the Marcellus Shale drilling joint development agreement with IOG executed in December 2015 and extended in June 2016. These fees did not recur during fiscal 2017. These factors, which contributed to increased earnings during the quarter ended June 30, 2017 compared to the quarter ended June 30, 2016, were partially offset by lower crude oil prices after hedging ($2.5 million), lower natural gas production ($1.8 million), lower crude oil production ($2.2 million), higher production costs ($1.2 million) and higher other taxes ($0.4 million). The increase in production costs is largely due to increased steam fuel costs, contract labor and repair and maintenance costs associated with operating wells on the West Coast, partially offset by a decrease in transportation and compression costs in the Appalachian region (largely due to the sale of Upper Devonian related wells in June 2016). The increase in other taxes was largely due to higher impact fees related to Appalachian production in the quarter ended June 30, 2017 compared to the quarter ended June 30, 2016. Impact fees were significantly lower in the quarter ended June 30, 2016 as a result of IOG's reimbursement of such costs for years prior to fiscal 2016. The increase in other taxes also reflects an increase in West Coast franchise taxes partially offset by a decrease in Kern, Ventura and Coalinga County taxes due to lower crude oil prices.

The Exploration and Production segment's earnings for the nine months ended June 30, 2017 were $99.0 million compared with a loss of $469.6 million for the nine months ended June 30, 2016. The increase in earnings primarily reflects the non-recurrence of the aforementioned impairment charges ($531.0 million). It also reflects higher natural gas production ($24.7 million), the impact of the aforementioned mark-to-market adjustments ($0.5 million), lower depletion expense ($17.7 million), lower other operating expenses ($4.1 million), lower interest expense ($1.0 million), the non-recurrence of joint development agreement professional fees ($4.6 million) and lower income tax expense ($3.4 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. 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 intercompany short-term borrowings. The decrease in income tax expense is largely due to an enhanced oil recovery tax credit related to Seneca's California properties, which was applicable this year as a result of relatively low domestic crude oil prices, partially offset by higher state taxes. The joint development agreement professional fees incurred were related to professional services associated with the Marcellus Shale drilling joint development agreement with IOG executed in December 2015 and extended in June 2016. These fees did not recur during fiscal 2017. These factors, which contributed to increased earnings during the nine months ended June 30, 2017 compared to the nine months ended June 30, 2016, were partially offset by lower crude oil prices after hedging ($4.9 million), lower natural gas prices after hedging ($3.0 million), lower crude oil production ($5.0 million), higher production costs ($4.8 million) and higher other taxes ($0.7 million). The increase in production costs is largely due to an increase in intercompany transportation costs associated with production volume transported by Midstream Corporation coupled with increased equipment rentals, contract labor and steam fuel costs partially offset by lower repair and maintenance costs associated with operating wells in Appalachia (impacted by the sale of Upper

Devonian related wells in June 2016) and on the West Coast. The increase in other taxes was largely due to higher impact fees related to Appalachian production in the nine months ended June 30, 2017 compared to the nine months ended June 30, 2016. Impact fees were significantly lower in the nine months ended June 30, 2016 as a result of IOG's reimbursement of such costs for years prior to fiscal 2016. The increase in other taxes also reflects an increase in West Coast franchise taxes partially offset by a decrease in Kern, Ventura and Coalinga County taxes due to lower crude oil prices.

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Pipeline and Storage

Pipeline and Storage Operating Revenues

(Thousands)	Three Months Ended June 30, 2017	2016	Increase (Decrease)	Nine Months Ended June 30, 2017	2016	Increase (Decrease)
Firm Transportation	$53,753	$56,734	$ (2,981)	$167,851	$173,139	$ (5,288)
Interruptible Transportation	353	1,034	(681)	1,391	3,056	(1,665)
	54,106	57,768	(3,662)	169,242	176,195	(6,953)
Firm Storage Service	17,391	17,423	(32)	52,468	52,802	(334)
Interruptible Storage Service	—	22	(22)	12	92	(80)
Other	195	580	(385)	879	1,810	(931)
	$71,692	$75,793	$ (4,101)	$222,601	$230,899	$ (8,298)

Pipeline and Storage Throughput

(MMcf)	Three Months Ended June 30, 2017	2016	Increase (Decrease)	Nine Months Ended June 30, 2017	2016	Increase (Decrease)
Firm Transportation	183,451	173,379	10,072	587,598	558,160	29,438
Interruptible Transportation	1,060	6,354	(5,294)	5,078	18,469	(13,391)
	184,511	179,733	4,778	592,676	576,629	16,047

2017 Compared with 2016

Operating revenues for the Pipeline and Storage segment decreased $4.1 million for the quarter ended June 30, 2017 as compared with the quarter ended June 30, 2016. The decrease was primarily due to a decrease in transportation revenues of $3.7 million. The decline in transportation revenues was due to a 2% reduction in Supply Corporation's rates effective November 1, 2016 as required by the rate case settlement approved by FERC on November 13, 2015. The decrease also reflects reductions in Empire's rates effective July 1, 2016 as required by the rate case settlement approved by FERC on December 13, 2016 combined with a decline in demand charges for transportation services as a result of contract terminations and contract restructuring.

Operating revenues for the Pipeline and Storage segment decreased $8.3 million for the nine months ended June 30, 2017 as compared with the nine months ended June 30, 2016. The decrease was primarily due to a decrease in transportation revenues of $7.0 million. The decline in transportation revenues was due to a 2% reduction in Supply Corporation's rates effective November 1, 2015 and an additional 2% reduction in Supply Corporation's rates effective November 1, 2016, both of which were required by the rate case settlement mentioned above. The decrease also reflects reductions to Empire's rates effective July 1, 2016 related to the rate case settlement mentioned above combined with a decline in demand charges for transportation services as a result of contract terminations and contract restructuring. Partially offsetting these decreases, transportation revenues benefited from a full nine months 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, and transportation revenues also benefited from a full nine months of revenue from Empire's Tuscarora Lateral Project, which was placed in service in November 2015.

Transportation volume for the quarter ended June 30, 2017 increased by 4.8 Bcf from the prior year’s quarter. For the nine months ended June 30, 2017, transportation volume increased by 16.0 Bcf from the prior year's nine-month period. The increase in transportation volume for the nine-month period primarily reflects the impact of a full nine months 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 termination 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 June 30, 2017 were $16.0 million, a decrease of $1.3 million when compared with earnings of $17.3 million for the quarter ended June 30, 2016. The decrease in earnings is primarily due to the earnings impact of lower transportation revenues of $2.4 million, as discussed above, combined with an increase in property taxes ($0.3 million). The increase in property taxes was a result of the various projects constructed over the last few

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years. These earnings decreases were partially offset by a decrease in depreciation expense ($0.3 million) and lower income tax expense ($1.2 million). The decrease in depreciation expense was attributable to a decrease in Empire's depreciation rates effective July 1, 2016 associated with Empire's rate case settlement. Income tax expense was lower due to provision-to-return adjustments combined with lower state taxes.

The Pipeline and Storage segment's earnings for the nine months ended June 30, 2017 were $54.7 million, a decrease of $5.1 million when compared with earnings of $59.8 million for the nine months ended June 30, 2016. The decrease in earnings is primarily due to the earnings impact of lower transportation revenues of $4.5 million, as discussed above, combined with higher operating expenses ($2.2 million), an increase in property taxes ($0.6 million) and a decrease in the allowance for funds used during construction (equity component) of $0.5 million. The increase in operating expenses primarily reflects an increase in compressor station costs, higher pension costs and increased personnel costs partially offset by a decrease in the reserve for preliminary project 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 partially offset by a decrease in depreciation expense ($1.0 million) and lower income tax expense ($1.7 million). The decrease in depreciation expense was attributable to a decrease in Empire's depreciation rates effective 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. Income tax expense was lower due to provision-to-return adjustments combined with lower state taxes and the adoption of the new accounting guidance regarding stock-based compensation.

Gathering

Gathering Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2017	2016	Increase (Decrease)	2017	2016	Increase (Decrease)
Gathering	$26,853	$25,417	$ 1,436	$82,629	$65,601	$ 17,028
Processing and Other Revenues	34	65	(31)	86	303	(217)
	$26,887	$25,482	$ 1,405	$82,715	$65,904	$ 16,811

Gathering Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2017	2016	Increase (Decrease)	2017	2016	Increase (Decrease)
Gathered Volume - (MMcf)	48,838	46,360	2,478	150,005	119,355	30,650

2017 Compared with 2016

Operating revenues for the Gathering segment increased $1.4 million for the quarter ended June 30, 2017 as compared with the quarter ended June 30, 2016. This increase was due to an increase in gathering revenues driven by a 2.5 Bcf increase in gathered volume. The overall increase in gathered volume was due to a 2.9 Bcf increase in gathered volume on Midstream Corporation's Clermont Gathering System (Clermont) and a 1.1 Bcf increase in gathered volume on Midstream Corporation's Wellsboro Gathering System (Wellsboro). The increases in the aforementioned volumes were largely due to increases in Seneca's Marcellus Shale production in these areas coupled with the impact of Wellsboro being placed into service in November 2016. These increases were partially offset by 1.3 Bcf decrease in gathered volume on Midstream Corporation's Trout Run Gathering System (Trout Run) and a 0.1 Bcf decrease in gathered volume on Midstream Corporation's Covington Gathering System (Covington) largely due to the natural decline of wells connected to these systems (no new wells were connected during the quarter ended June 30, 2017).

Operating revenues for the Gathering segment increased $16.8 million for the nine months ended June 30, 2017 as compared with the nine months ended June 30, 2016. This increase was due to an increase in gathering revenues driven by a 30.7 Bcf increase in gathered volume. The overall increase in gathered volume was due to a 19.3 Bcf increase in gathered volume on Clermont, a 4.0 Bcf increase in gathered volume on Trout Run, a 3.9 Bcf increase in gathered volume on Wellsboro (which was placed into service in November 2016) and a 3.5 Bcf increase in gathered volume on Covington. The increases in the aforementioned volumes were largely due to increases in Seneca's Marcellus Shale production due to the non-recurrence of pricing-related curtailments that existed in fiscal 2016, partially offset by a natural decline of wells connected to the Trout Run and Covington systems.

The Gathering segment's earnings for the quarter ended June 30, 2017 were $10.1 million, an increase of $0.6 million when compared with earnings of $9.5 million for the quarter ended June 30, 2016. The increase in earnings is mainly due to an increase in gathering revenues ($0.9 million) and lower income tax expense ($0.3 million). The increase in gathering revenues is due to the increases in gathered volume discussed above. The decrease in income tax expense was due to the impact of a provision-to-return adjustment. These were partially offset by higher interest expense ($0.4 million) and higher depreciation expense ($0.3 million). The increase in interest expense is the result of an increase in short-term intercompany borrowings coupled with a decrease in capitalized interest (which increases interest expense). An increase in plant balances led to an increase in depreciation expense.

The Gathering segment's earnings for the nine months ended June 30, 2017 were $31.4 million, an increase of $9.4 million when compared with earnings of $22.0 million for the nine months ended June 30, 2016. The increase in earnings is mainly due to an increase in gathering revenues ($11.1 million). The increase in gathering revenues is due to the increases in gathered volume discussed above. These were partially offset by higher operating expenses ($0.9 million) and higher income tax expense ($0.6 million). The increase in operating expenses were largely due to the ramp up in operations in Clermont and Trout Run (which increased compression and other variable costs) coupled with higher personnel costs. An increase in state taxes, partially offset by the impact of a provision-to-return adjustment, led to an increase in income tax expense.

Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2017	2016	Increase (Decrease)	2017	2016	Increase (Decrease)
Retail Sales Revenues:						
Residential	$85,627	$72,018	$ 13,609	$383,604	$315,927	$ 67,677
Commercial	11,045	8,400	2,645	53,118	39,866	13,252
Industrial	547	185	362	2,082	1,604	478
	97,219	80,603	16,616	438,804	357,397	81,407
Transportation	26,033	25,740	293	111,701	106,751	4,950
Off-System Sales	—	—	—	3,982	1,877	2,105
Other	2,039	1,954	85	7,646	7,886	(240)
	$125,291	$108,297	$ 16,994	$562,133	$473,911	$ 88,222

Utility Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2017	2016	Increase (Decrease)	2017	2016	Increase (Decrease)
Retail Sales:						
Residential	8,105	9,209	(1,104)	48,817	46,828	1,989
Commercial	1,170	1,254	(84)	7,373	6,770	603

Industrial	48	—	48	282	233	49
	9,323	10,463	(1,140)	56,472	53,831	2,641
Transportation	13,799	14,857	(1,058)	60,453	59,770	683
Off-System Sales	—	—	—	1,295	1,243	52
	23,122	25,320	(2,198)	118,220	114,844	3,376

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Degree Days

Three Months Ended June 30,	Normal	2017	2016	Percent Colder (Warmer) Than Normal(1)	Prior Year(1)
Buffalo	912	767	927	(15.9)%	(17.3)%
Erie	871	705	936	(19.1)%	(24.7)%
Nine Months Ended June 30,					
Buffalo	6,455	5,599	5,567	(13.3)%	0.6 %
Erie	6,023	5,082	5,159	(15.6)%	(1.5)%

(1) Percents compare actual 2017 degree days to normal degree days and actual 2017 degree days to actual 2016 degree days.

2017 Compared with 2016

Operating revenues for the Utility segment increased $17.0 million for the quarter ended June 30, 2017 as compared with the quarter ended June 30, 2016. The increase largely resulted from a $16.6 million increase in retail gas sales revenues and a $0.3 million increase in transportation revenues. The increase in retail gas sales revenues was the result of an increase in the cost of gas sold (per Mcf) that offset the impact of lower volumes. The increase in transportation revenues (despite the lower volumes and warmer weather) was largely due to an increase in the price at which marketers cashed-out their gas imbalances with the Utility for the quarter ended June 30, 2017 compared to the quarter ended June 30, 2016 as commodity gas prices increased.

Operating revenues for the Utility segment increased $88.2 million for the nine months ended June 30, 2017 as compared with the nine months ended June 30, 2016. The increase largely resulted from an $81.4 million increase in retail gas sales revenues. In addition, there was a $5.0 million increase in transportation revenues, and a $2.1 million increase in off-system sales (due to higher sales prices coupled with slightly higher volumes). The increase in retail gas sales revenues was largely a result of an increase in the cost of gas sold (per Mcf) coupled with a slight increase in volumes. The increase in transportation revenues was due to the increase in the price paid by marketers to cash-out their imbalances with the Utility coupled with a slight increase in transportation throughput. Due to profit sharing with retail customers, the margins related to off-system sales are minimal.

The Utility segment’s earnings for the quarter ended June 30, 2017 were $4.3 million, an increase of $2.1 million when compared with earnings of $2.2 million for the quarter ended June 30, 2016. The increase in earnings was largely attributable to lower operating expenses of $1.8 million (primarily due to lower pension and personnel costs) and lower income tax expense of $1.0 million (largely due to the impact of a provision-to-return adjustment), partially offset by higher depreciation expense of $0.6 million (largely due to higher plant balances including the impact of the Utility segment’s legacy mainframe system replacement). Margins during the quarter ended June 30, 2017 were relatively flat compared to June 30, 2016 as the margin impact of the rate order issued by the NYPSC (effective on April 1, 2017) and usage were offset by the impact of warmer weather.

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 June 30, 2017, the WNC increased earnings by approximately $0.5 million, as the weather was warmer than normal. For the quarter ended June 30, 2016, the WNC increased earnings by approximately $0.1 million, as the weather was warmer than normal.

The Utility segment's earnings for the nine months ended June 30, 2017 were $51.1 million, a decrease of $1.6 million when compared with earnings of $52.7 million for the nine months ended June 30, 2016. The decrease in earnings was largely attributable to higher operating expenses of $3.9 million (primarily due to higher personnel costs including the impact of post implementation costs related to the replacement of the Utility segment's legacy mainframe system), higher depreciation expense of $2.6 million (largely due to higher plant balances including the impact of the legacy mainframe system replacement) and a decrease in the allowance for funds used during construction (equity component) of $0.9 million (due to the replacement of the Utility segment's legacy mainframe system that was placed in service in May 2016). These were partially offset by the positive earnings impact associated with higher usage ($2.2 million), the impact of regulatory adjustments ($1.9 million, including the $0.9 million margin impact related to the new rate order issued by the NYPSC effective April, 1 2017) and lower income tax expense of $0.9 million (largely due to the impact of a provision-to-return adjustment). Usage refers to consumption after factoring out any impact that weather may have had on consumption.

For the nine months ended June 30, 2017, the WNC increased earnings by approximately $4.3 million, as the weather was warmer than normal. For the nine months ended June 30, 2016, the WNC increased earnings by approximately $4.4 million, as the weather was warmer than normal.

Energy Marketing

Energy Marketing Operating Revenues

(Thousands)	Three Months Ended June 30, 2017	2016	Increase (Decrease)	Nine Months Ended June 30, 2017	2016	Increase (Decrease)
Natural Gas (after Hedging)	$25,017	$17,635	$ 7,382	$112,753	$78,574	$ 34,179
Other	8	4	4	57	108	(51)
	$25,025	$17,639	$ 7,386	$112,810	$78,682	$ 34,128

Energy Marketing Volume

	Three Months Ended June 30, 2017	2016	Increase (Decrease)	Nine Months Ended June 30, 2017	2016	Increase (Decrease)
Natural Gas – (MMcf)	7,722	8,537	(815)	32,969	33,800	(831)

2017 Compared with 2016

Operating revenues for the Energy Marketing segment increased $7.4 million for the quarter ended June 30, 2017 as compared with the quarter ended June 30, 2016. Operating revenues for the Energy Marketing segment increased $34.1 million for the nine months ended June 30, 2017 as compared with the nine months ended June 30, 2016. The increase for the quarter and nine-month period is primarily due to an increase in gas sales revenue due to a higher average price of natural gas period over period, partially offset by a decrease in volume sold to retail customers.

The Energy Marketing segment recorded losses of $0.6 million for both the quarters ended June 30, 2017 and June 30, 2016. While operating revenues increased for the quarter ended June 30, 2017 as compared with the quarter ended June 30, 2016, the increase was substantially offset by higher purchased gas costs. The Energy Marketing segment earnings for the nine months ended June 30, 2017 were $2.1 million, a decrease of $2.0 million when compared with earnings of $4.1 million for the nine months ended June 30, 2016. This decrease in earnings for the nine-month period was primarily attributable to lower margin of $1.9 million. The decrease in margin largely reflects a decline in average margin per Mcf primarily due to stronger natural gas prices at local pricing points relative to NYMEX-based sales contracts, combined with the margin impact associated with the decrease in volume sold to retail customers during the nine months ended June 30, 2017 compared to the nine months ended June 30, 2016.

Corporate and All Other

2017 Compared with 2016

Corporate and All Other operations had a loss of $0.3 million for the quarter ended June 30, 2017 compared to a loss of $0.9 million for the quarter ended June 30, 2016. The improvement is primarily attributed to lower income tax expense ($1.6 million) partially offset by lower margins ($0.6 million) from the sale of standing timber by Seneca's land and timber division and higher operating expenses ($0.4 million) resulting from higher personnel costs.

For the nine months ended June 30, 2017, Corporate and All Other operations recorded a loss of $0.3 million, a decrease of $2.8 million when compared with earnings of $2.5 million for the nine months ended June 30, 2016. The decrease in earnings for the nine-month period can be attributed to higher operating expenses ($1.1 million) resulting from higher personnel costs, higher income tax expense ($0.5 million) and lower margins ($1.0 million) from the sale of standing timber by Seneca’s land and timber division.

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

Interest on long-term debt increased $0.3 million for the quarter ended June 30, 2017 as compared with the quarter ended June 30, 2016. This increase is due to a decrease in the capitalization of interest costs (mostly in Midstream Corporation). For the nine months ended June 30, 2017, interest on long-term debt decreased $1.0 million as compared with the nine months ended June 30, 2016. This decrease is due to an increase in the capitalization of interest costs (mostly in Midstream Corporation) as a result of various projects being placed into service, which decreased interest expense for the nine months ended June 30, 2017 as compared to the nine months ended June 30, 2016.

CAPITAL RESOURCES AND LIQUIDITY

The Company's primary sources of cash during the nine-month periods ended June 30, 2017 and June 30, 2016 consisted of cash provided by operating activities and proceeds from Seneca's joint development agreement with IOG. With regard to development costs incurred by Seneca prior to the joint development agreement, reimbursement proceeds from IOG are reflected as net proceeds from the sale of oil and gas producing properties on the Statement of Cash Flows. As for joint development costs incurred after the execution of the joint development agreement, proceeds received from IOG serve as a reduction to capital expenditures on the Statement of Cash Flows. These sources of cash were supplemented by net proceeds from the issuance of common stock for both the nine months ended June 30, 2017 and June 30, 2016, 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 $551.1 million for the nine months ended June 30, 2017, an increase of $91.1 million compared with $460.0 million provided by operating activities for the nine months ended June 30, 2016. 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.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company’s expenditures for long-lived assets totaled $301.8 million during the nine months ended June 30, 2017 and $407.2 million during the nine months ended June 30, 2016. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Nine Months Ended June 30, (Millions)	2017		2016		Increase(Decrease)
Exploration and Production:					
Capital Expenditures	$168.5	(1)	$214.9	(2)	$ (46.4)
Pipeline and Storage:					
Capital Expenditures	53.5	(1)	76.0	(2)	(22.5)
Gathering:					
Capital Expenditures	23.7	(1)	43.7	(2)	(20.0)
Utility:					
Capital Expenditures	56.4	(1)	72.3	(2)	(15.9)
All Other:					
Capital Expenditures	0.2	(1)	0.3	(2)	(0.1)
Eliminations	(0.5)		—		(0.5)
	$301.8		$407.2		$ (105.4)

(1) At June 30, 2017, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $25.0 million, $10.3 million, $5.2 million and $7.0 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 June 30, 2016, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $26.7 million, $7.6 million, $2.8 million and $7.3 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 nine months ended June 30, 2017 were primarily well drilling and completion expenditures and included approximately $137.6 million for the Appalachian region (including $110.2 million in the Marcellus Shale area) and $30.9 million for the West Coast region. These amounts included approximately $73.0 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. 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. Of this amount, IOG has funded $262.5 million as of June 30, 2017, which includes $163.9 million of cash ($137.3 million in fiscal 2016 and $26.6 million in fiscal 2017) that Seneca had received 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 were recorded by Seneca as a $163.9 million reduction of property, plant and equipment. The remainder funded joint development expenditures. 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 nine months ended June 30, 2016 were primarily well drilling and completion expenditures and included approximately $184.9 million for the Appalachian region (including $172.9

million in the Marcellus Shale area) and $30.0 million for the West Coast region. These amounts included approximately $85.4 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2017 were mainly for expenditures related to Empire and Supply Corporation's Northern Access 2016 Project ($21.0 million) and Supply Corporation's Line D Expansion Project ($8.4 million), as discussed below. In addition, the Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2017 also include additions, improvements and replacements to this segment's transmission and gas storage systems. The Pipeline and Storage capital expenditures for the nine months ended June 30, 2016 were mainly for expenditures related to Empire and Supply Corporation's Northern Access 2016 Project ($22.4 million), Supply Corporation's Northern Access 2015 Project ($12.9 million), Supply Corporation's Westside Expansion and Modernization Project ($7.0 million), Empire and Supply Corporation's Tuscarora Lateral Project ($5.9 million) and Supply Corporation's Line D Expansion Project ($5.4 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 incurring 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 June 30, 2017, the total amount reserved for the Pipeline and Storage segment's preliminary survey and investigation costs was $6.4 million.

Supply Corporation and Empire are working on, 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 preliminary cost estimate for the Northern Access 2016 project is approximately $500 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 February 3, 2017, the Company received FERC approval of the project. On April 7, 2017, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received on January 27, 2017). The Company remains committed to the project. On April 21, 2017, the Company appealed the NYDEC's decision with regard to the Water Quality Certification to the United States Court of Appeals for the Second Circuit, and on May 11, 2017, the Company commenced legal action in New York State Supreme Court challenging the NYDEC's actions with regard to various state permits. In light of the pending legal action, the Company has not yet determined a revised target in-service date. As of June 30, 2017, approximately $73.7 million has been spent on the Northern Access 2016 project, including $20.1 million that has been spent to study the project, for which no reserve has been established. The remaining $53.6 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 4,140 horsepower Keelor Compressor Station and modifications to the Bowen compressor station at an estimated capital cost of approximately $27.9 million. The project will also provide system modernization benefits.

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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. The Bowen work has been completed, and on April 17, 2017, Supply Corporation received from the PaDEP a Plan Approval Permit under its Air Quality Program for the facilities to be installed at the Keelor Compressor Station. Supply Corporation has begun construction activities at Keelor, targeting a project in-service date of November 1, 2017. As of June 30, 2017, approximately $18.8 million has been capitalized as Construction Work in Progress for the Line D Expansion project.

Empire concluded an Open Season on November 18, 2015, for a project that would allow for the transportation of additional shale supplies from Millennium Pipeline at Corning, from Supply Corporation at Tuscarora, or from interconnections in Tioga County, Pennsylvania, to the TransCanada Pipeline, the TGP 200 Line and potentially other on-system points ("Empire North Project"). Empire has executed a Precedent Agreement with a foundation shipper for 150,000 Dth per day of transportation capacity and with another shipper for 35,000 Dth per day and is negotiating precedent agreements with other prospective shippers. The project, which has a projected in-service date of November 1, 2019, will be designed for up to 205,000 Dth per day; capital costs are expected to be approximately $135 million. As of June 30, 2017, 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 June 30, 2017.

Supply Corporation has entered into a foundation shipper Precedent Agreement to provide incremental natural gas transportation services from Line N to the ethylene cracker facility being constructed by Shell Chemical Appalachia, LLC in Potter Township, Pennsylvania. Supply Corporation has completed an Open Season for the project and has secured incremental firm transportation capacity commitments totaling 133,000 Dth per day on Line N and on the proposed 4-mile pipeline extension from Line N to the facility. The proposed in-service date for this project is as early as July 1, 2019. As of June 30, 2017, approximately $0.1 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 June 30, 2017.

Gathering

The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2017 and June 30, 2016 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 June 30, 2017, approximately $274.8 million has been spent on the Clermont Gathering System, including approximately $15.2 million spent during the nine months ended June 30, 2017, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2017.

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 June 30, 2017, the Company has spent approximately $172.7 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2017.

Utility

The majority of the Utility segment capital expenditures for the nine months ended June 30, 2017 and June 30, 2016 were made for replacement of mains and main extensions, as well as for the replacement of service lines. The capital expenditures for the nine months ended June 30, 2016 also included $14.0 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, the Company expects to use cash on hand and cash from operations as the first means of financing these projects during the remainder of fiscal 2017 and throughout fiscal 2018. The Company may issue short-term and long-term debt as necessary during fiscal 2018 to help meet its capital expenditure needs. The level of short-term and long-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 levels of production from existing wells.

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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 did not have any consolidated short-term debt outstanding at June 30, 2017 or September 30, 2016, nor was there any short-term debt outstanding during the nine months ended June 30, 2017. 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 14 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 June 30, 2017, the Company’s debt to capitalization ratio (as calculated under the facility) was .55. The constraints specified in the Credit Agreement would have permitted an additional $1.40 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 June

30, 2017, the Company did not have any debt outstanding under the Credit Agreement.

The Current Portion of Long-Term Debt at June 30, 2017 consists of $300 million aggregate principal amount of 6.50% notes that mature in April 2018. Currently, the Company expects to refund these notes with cash on hand, short-term borrowings and/or long-term debt. None of the Company's long-term debt at June 30, 2016 had a maturity date within the following twelve-month period.

The Company's embedded cost of long-term debt (including the current portion of long-term debt) was 5.52% and 5.53% at June 30, 2017 and June 30, 2016, respectively.

Under the Company's existing indenture covenants at June 30, 2017, the Company would have been permitted to issue up to a maximum of $394.0 million in additional long-term indebtedness at then current market interest rates in addition to being

able to issue new indebtedness to replace maturing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company's ability to issue additional long-term unsecured indebtedness for a period up to nine calendar months, beginning with the fourth calendar month following the loss. This would not preclude the Company from issuing new indebtedness to replace maturing debt. 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 June 30, 2017) 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 $23.8 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 nine months ended June 30, 2017, the Company contributed $15.1 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $3.2 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2017, the Company may contribute up to $5.0 million to the Retirement Plan. In the remainder of 2017, the Company expects to contribute approximately $0.5 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as “swap dealers” and “major swap participants,” (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC’s enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that 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 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 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 June 30, 2017, 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

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, among other things. On January 23, 2017, the administrative law judge assigned to the proceeding issued a recommended decision (RD) in the case. The RD, as revised on January 26, 2017, recommended a rate increase designed to provide additional annual revenues of $8.5 million, an equity ratio, subject to update of 42.3% based on the Company’s equity ratio, and a cost of equity, subject to update of 8.6%. On April 20, 2017, the NYPSC issued an Order adopting some provisions of the RD and modifying or rejecting others. The Order provides for an annual rate increase of $5.9 million. The rate increase became effective May 1, 2017. The Order further provides for a return on equity of 8.7%, and established an equity ratio of 42.9%. The Order also directs the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018, only if the Company does not file for new rates to become effective on or before October 1, 2018.

On July 28, 2017, Distribution Corporation filed an appeal with New York State Supreme Court, Albany County, seeking review of the rate order. The appeal contends that portions of the rate order should be invalidated because they fail to meet the applicable legal standard for agency decisions. The Company cannot predict the outcome of the appeal at this time.

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 currently has no active rate case on file. 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.

Empire currently has no active rate case on file. Empire's current rate settlement requires a rate case filing no later than July 1, 2021.

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. The EPA previously adopted final regulations that set methane and volatile organic compound emissions standards for new or modified oil and gas emissions sources. These rules impose more stringent leak detection and repair requirements, and further address reporting and control of methane and volatile organic compound emissions. The current administration has issued executive orders to roll back many of these regulations, and, in turn, litigation has been instituted to challenge the administration's efforts. The Company must continue to comply with all applicable regulations. 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.

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New Authoritative Accounting and Financial Reporting Guidance

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

Safe Harbor for Forward-Looking Statements

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

1. 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;

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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 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;
17. 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;
18. The creditworthiness or performance of the Company’s key suppliers, customers and counterparties;
19. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;
20. Significant differences between the Company’s projected and actual capital expenditures and operating expenses; 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 June 30, 2017.

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 June 30, 2017 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

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Part II. Other Information

Item 1. Legal Proceedings

As previously reported, 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 alleged environmental and administrative violations occurred during inspections of various sites and facilities in four counties over a two-year period. Seneca paid a civil penalty of $375,000 in March 2017, officially settling this matter with the PaDEP in April 2017.

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, as amended by Item 1A of Part II of the Company’s Form 10-Q for the quarter ended March 31, 2017, have not materially changed.

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

On April 3, 2017, the Company issued a total of 6,660 unregistered shares of Company common stock to nine non-employee directors of the Company then serving on the Board of Directors of the Company, 740 shares to each such director. All of these unregistered shares were issued under the Company’s 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors’ services during the quarter ended June 30, 2017. 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]
Apr. 1 - 30, 2017	—	N/A	—	6,971,019
May 1 - 31, 2017	1,324	$55.23	—	6,971,019
June 1 - 30, 2017	721	$58.52	—	6,971,019
Total	2,045	$56.39	—	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 June 30, 2017, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program.

(b)

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

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Item 6. Exhibits

Exhibit Number	Description of Exhibit
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2017 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 June 30, 2017 and 2016.
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 and nine months ended June 30, 2017 and 2016, (ii) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2017 and 2016, (iii) the Consolidated Balance Sheets at June 30, 2017 and September 30, 2016, (iv) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2017 and 2016 and (v) the Notes to Condensed Consolidated Financial Statements.

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

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SIGNATURES

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

NATIONAL FUEL GAS COMPANY
(Registrant)

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

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

Date: August 4, 2017