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, 2018

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 ☑ NO ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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	☑		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 ☑

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, 2018: 85,951,198 shares.

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 Company	National Fuel Gas Midstream Company, LLC (formerly National Fuel Gas Midstream Corporation) *
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
Seneca	Seneca Resources Company, LLC (formerly Seneca Resources Corporation) *
Supply Corporation	National Fuel Gas Supply Corporation

* Effective August 1, 2018, the Company converted Seneca Resources Corporation and National Fuel Gas Midstream Corporation to limited liability companies (LLCs) for tax purposes. Both LLCs are wholly owned by a newly formed subsidiary named Pennsylvania Gas Holdings Corporation which in turn is wholly owned by the Company.

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

2017 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2017
2017 Tax Reform Act	Tax legislation referred to as the "Tax Cuts and Jobs Act," enacted December 22, 2017.
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.
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.
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
Utica Shale	A Middle Ordovician-age geological formation lying several thousand feet below the Marcellus Shale in the Appalachian region of the United States, including much of Ohio, Pennsylvania, West Virginia and southern New York.
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.

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)	2018	2017	2018	2017
INCOME				
Operating Revenues:				
Utility and Energy Marketing Revenues	$ 154,088	$ 146,360	$ 719,234	$ 663,029
Exploration and Production and Other Revenues	137,492	151,925	425,811	473,617
Pipeline and Storage and Gathering Revenues	51,332	50,083	158,428	156,298
	342,912	348,368	1,303,473	1,292,944
Operating Expenses:				
Purchased Gas	52,211	46,135	322,854	264,349
Operation and Maintenance:				
Utility and Energy Marketing	45,618	44,467	158,397	158,796
Exploration and Production and Other	31,141	34,098	106,268	102,153
Pipeline and Storage and Gathering	24,770	23,250	67,450	69,016
Property, Franchise and Other Taxes	20,595	21,447	64,245	64,368
Depreciation, Depletion and Amortization	60,817	55,617	177,802	168,812
	235,152	225,014	897,016	827,494
Operating Income	107,760	123,354	406,457	465,450
Other Income (Expense):				
Interest Income	1,632	853	4,907	2,844
Other Income	999	1,370	3,492	4,728
Interest Expense on Long-Term Debt	(27,177)	(29,225)	(82,412)	(87,241)
Other Interest Expense	(1,006)	(846)	(2,742)	(2,680)
Income Before Income Taxes	82,208	95,506	329,702	383,101
Income Tax Expense (Benefit)	19,183	35,792	(23,825)	145,195
Net Income Available for Common Stock	63,025	59,714	353,527	237,906
EARNINGS REINVESTED IN THE BUSINESS				
Balance at Beginning of Period	1,070,939	817,348	851,669	676,361
	1,133,964	877,062	1,205,196	914,267
Dividends on Common Stock	(36,526)	(35,469)	(107,758)	(104,590)
Cumulative Effect of Adoption of Authoritative Guidance for Stock-Based Compensation	—	—	—	31,916
Balance at June 30	$ 1,097,438	$ 841,593	$ 1,097,438	$ 841,593
Earnings Per Common Share:				
Basic:				
Net Income Available for Common Stock	$ 0.73	$ 0.70	$ 4.12	$ 2.79
Diluted:				
Net Income Available for Common Stock	$ 0.73	$ 0.69	$ 4.09	$ 2.77
Weighted Average Common Shares Outstanding:				
Used in Basic Calculation	85,930,289	85,422,313	85,789,279	85,315,154
Used in Diluted Calculation	86,501,194	86,064,464	86,370,900	85,950,742
Dividends Per Common Share:				
Dividends Declared	$ 0.425	$ 0.415	$ 1.255	$ 1.225

See Notes to Condensed Consolidated Financial Statements

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

(Thousands of Dollars)	Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Nine Months Ended June 30, 2018	Nine Months Ended June 30, 2017
Net Income Available for Common Stock	$ 63,025	$ 59,714	$ 353,527	$ 237,906
Other Comprehensive Income (Loss), Before Tax:				
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(121)	1,437	(843)	2,280
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(37,452)	18,233	(55,534)	9,829
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	—	—	(430)	(741)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	3,771	(18,452)	(5,577)	(59,641)
Other Comprehensive Income (Loss), Before Tax	(33,802)	1,218	(62,384)	(48,273)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	42	532	(275)	832
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(10,416)	7,592	(16,240)	3,892
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	—	—	(158)	(272)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	1,208	(7,693)	(3,438)	(25,061)
Income Taxes – Net	(9,166)	431	(20,111)	(20,609)
Other Comprehensive Income (Loss)	(24,636)	787	(42,273)	(27,664)
Comprehensive Income	$ 38,389	$ 60,501	$ 311,254	$ 210,242

See Notes to Condensed Consolidated Financial Statements

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2018	September 30, 2017
ASSETS		
Property, Plant and Equipment	$ 10,254,976	$ 9,945,560
Less - Accumulated Depreciation, Depletion and Amortization	5,411,746	5,271,486
	4,843,230	4,674,074
Current Assets		
Cash and Temporary Cash Investments	313,307	555,530
Hedging Collateral Deposits	2,283	1,741
Receivables – Net of Allowance for Uncollectible Accounts of $26,711 and $22,526, Respectively	151,005	112,383
Unbilled Revenue	18,930	22,883
Gas Stored Underground	16,090	35,689
Materials and Supplies - at average cost	34,693	33,926
Unrecovered Purchased Gas Costs	—	4,623
Other Current Assets	52,690	51,505
	588,998	818,280
Other Assets		
Recoverable Future Taxes	115,688	181,363
Unamortized Debt Expense	7,587	1,159
Other Regulatory Assets	171,792	174,433
Deferred Charges	37,349	30,047
Other Investments	130,744	125,265
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	61,371	56,370
Fair Value of Derivative Financial Instruments	11,760	36,111
Other	108	742
	541,875	610,966
Total Assets	$ 5,974,103	$ 6,103,320

See Notes to Condensed Consolidated Financial Statements

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2018	September 30, 2017
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 85,943,875 Shares and 85,543,125 Shares, Respectively	$ 85,944	$ 85,543
Paid in Capital	816,395	796,646
Earnings Reinvested in the Business	1,097,438	851,669
Accumulated Other Comprehensive Loss	(72,396)	(30,123)
Total Comprehensive Shareholders' Equity	1,927,381	1,703,735
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	1,835,582	2,083,681
Total Capitalization	3,762,963	3,787,416
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	250,000	300,000
Accounts Payable	111,812	126,443
Amounts Payable to Customers	16,833	—
Dividends Payable	36,526	35,500
Interest Payable on Long-Term Debt	28,357	35,031
Customer Advances	197	15,701
Customer Security Deposits	18,468	20,372
Other Accruals and Current Liabilities	161,252	111,889
Fair Value of Derivative Financial Instruments	38,012	1,103
	661,457	646,039
Deferred Credits		
Deferred Income Taxes	491,520	891,287
Taxes Refundable to Customers	366,183	95,739
Cost of Removal Regulatory Liability	213,560	204,630
Other Regulatory Liabilities	128,184	113,716
Pension and Other Post-Retirement Liabilities	138,275	149,079
Asset Retirement Obligations	101,833	106,395
Other Deferred Credits	110,128	109,019
	1,549,683	1,669,865
Commitments and Contingencies (Note 6)	—	—
Total Capitalization and Liabilities	$ 5,974,103	$ 6,103,320

See Notes to Condensed Consolidated Financial Statements

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

(Thousands of Dollars)	Nine Months Ended June 30, 2018	2017
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 353,527	$ 237,906
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	177,802	168,812
Deferred Income Taxes	(43,537)	105,073
Stock-Based Compensation	11,770	8,857
Other	12,311	11,084
Change in:		
Hedging Collateral Deposits	(542)	(658)
Receivables and Unbilled Revenue	(35,021)	(15,885)
Gas Stored Underground and Materials and Supplies	18,832	15,699
Unrecovered Purchased Gas Costs	4,623	(1,317)
Other Current Assets	(1,185)	8,502
Accounts Payable	2,327	5,046
Amounts Payable to Customers	16,833	(6,467)
Customer Advances	(15,504)	(14,538)
Customer Security Deposits	(1,904)	1,503
Other Accruals and Current Liabilities	26,538	25,423
Other Assets	(10,770)	(3,548)
Other Liabilities	1,441	5,638
Net Cash Provided by Operating Activities	517,541	551,130
INVESTING ACTIVITIES		
Capital Expenditures	(403,994)	(314,774)
Net Proceeds from Sale of Oil and Gas Producing Properties	55,506	26,554
Other	(1,759)	(10,186)
Net Cash Used in Investing Activities	(350,247)	(298,406)
FINANCING ACTIVITIES		
Reduction of Long-Term Debt	(307,047)	—
Dividends Paid on Common Stock	(106,732)	(103,594)
Net Proceeds from Issuance of Common Stock	4,262	6,223
Net Cash Used in Financing Activities	(409,517)	(97,371)
Net Increase (Decrease) in Cash and Temporary Cash Investments	(242,223)	155,353
Cash and Temporary Cash Investments at October 1	555,530	129,972
Cash and Temporary Cash Investments at June 30	$ 313,307	$ 285,325
Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$ 71,410	$ 47,508

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.

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, 2017 , 2016 and 2015 that are included in the Company's 2017 Form 10-K. The consolidated financial statements for the year ended September 30, 2018 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, 2018 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2018 . 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 $14.7 million at June 30, 2018 , 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 $96.3 million and $80.9 million at June 30, 2018 and September 30, 2017 , respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with 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, 2018, the ceiling exceeded the book value of the oil and gas properties by approximately $462.3 million . In adjusting estimated future cash flows for hedging under the ceiling test at June 30, 2018 , estimated future net cash flows were decreased by $6.7 million .

The Company entered into a purchase and sale agreement to sell its oil and gas properties in the Sespe Field area of Ventura County, California in October 2017 for $43.0 million . The Company completed the sale on May 1, 2018, effective as of October 1, 2017, receiving net proceeds of $38.2 million (included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statement of Cash Flows for the nine months ended June 30, 2018). The net proceeds received by the Company were adjusted for production revenue and production expenses retained by the Company between the effective date of the sale and the closing date, resulting in lower proceeds from sale at the closing date. The divestiture of the Company's oil and gas properties in the Sespe Field reflects continuing efforts to focus West Coast development activities in the San Joaquin basin, particularly at the Midway Sunset field in Kern County, California. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

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 jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. IOG holds an 80% working interest in all of the joint development wells. In total, IOG has funded $305.3 million as of June 30, 2018 for its 80% working interest in the 75 joint development wells, which includes $181.2 million of cash ($137.3 million in fiscal 2016, $26.6 million in fiscal 2017 and $17.3 million in the nine months ended June 30, 2018) included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statements of Cash Flows for fiscal 2016, fiscal 2017 and for the nine months ended June 30, 2018, respectively. Such proceeds from sale represent funding received from IOG for costs previously incurred by Seneca to develop a portion of the 75 joint development wells. As the fee-owner of the property's mineral rights, Seneca currently retains a 7.5% royalty interest and the remaining 20% working interest (26% net revenue interest) in 56 of the joint development wells. In the remaining 19 wells, Seneca retains a 20% working and net revenue interest. Seneca's working interest under the agreement will increase to 85% after IOG achieves a 15% internal rate of return.

Accumulated Other Comprehensive Loss. The components of Accumulated Other Comprehensive Loss and changes for the quarter and nine months ended June 30, 2018 and 2017, 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, 2018				
Balance at April 1, 2018	$ 3,841	$ 6,885	$ (58,486)	$ (47,760)
Other Comprehensive Gains and Losses Before Reclassifications	(27,036)	(163)	—	(27,199)
Amounts Reclassified From Other Comprehensive Income (Loss)	2,563	—	—	2,563
Balance at June 30, 2018	$ (20,632)	$ 6,722	$ (58,486)	$ (72,396)
Nine Months Ended June 30, 2018				
Balance at October 1, 2017	$ 20,801	$ 7,562	$ (58,486)	$ (30,123)
Other Comprehensive Gains and Losses Before Reclassifications	(39,294)	(568)	—	(39,862)
Amounts Reclassified From Other Comprehensive Income (Loss)	(2,139)	(272)	—	(2,411)
Balance at June 30, 2018	$ (20,632)	$ 6,722	$ (58,486)	$ (72,396)
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)

Reclassifications Out of Accumulated Other Comprehensive Loss. The details about the reclassification adjustments out of accumulated other comprehensive loss for the quarter and nine months ended June 30, 2018 and 2017 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Loss Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Loss: Three Months Ended June 30, 2018	Three Months Ended June 30, 2017	Nine Months Ended June 30, 2018	Nine Months Ended June 30, 2017	Affected Line Item in the Statement Where Net Income is Presented
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:					
Commodity Contracts	($3,249)	$18,600	$6,125	$62,030	Operating Revenues
Commodity Contracts	5	21	952	(1,938)	Purchased Gas
Foreign Currency Contracts	(527)	(169)	(1,500)	(451)	Operation and Maintenance Expense
Gains (Losses) on Securities Available for Sale	—	—	430	741	Other Income
	(3,771)	18,452	6,007	60,382	Total Before Income Tax
	1,208	(7,693)	(3,596)	(25,333)	Income Tax Expense
	($2,563)	$10,759	$2,411	$35,049	Net of Tax

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

	At June 30, 2018	At September 30, 2017
Prepayments	$ 10,594	$ 10,927
Prepaid Property and Other Taxes	11,177	13,974
Federal Income Taxes Receivable	17,216	—
State Income Taxes Receivable	5,065	9,689
Fair Values of Firm Commitments	1,350	1,031
Regulatory Assets	7,288	15,884
	$ 52,690	$ 51,505

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

	At June 30, 2018	At September 30, 2017
Accrued Capital Expenditures	$ 53,534	$ 37,382
Regulatory Liabilities	43,167	34,059
Reserve for Gas Replacement	14,651	—
Federal Income Taxes Payable	—	1,775
2017 Tax Reform Act Regulatory Refund	11,817	—
Other	38,083	38,673
	$ 161,252	$ 111,889

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 had outstanding were stock options, SARs, restricted stock units and performance shares. For the quarter and nine months ended June 30, 2018, 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 1,095,838 securities and 316,279 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2018, respectively. There were 172,500 securities and 157,638 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2017, respectively.

Stock-Based Compensation. The Company granted 208,588 performance shares during the nine months ended June 30, 2018 . The weighted average fair value of such performance shares was $50.95 per share for the nine months ended June 30, 2018 . 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, 2018 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2017 to September 30, 2020. 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, 2018 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2017 to September 30, 2020. 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 89,672 non-performance based restricted stock units during the nine months ended June 30, 2018 . The weighted average fair value of such non-performance based restricted stock units was $51.23 per share for the nine months ended June 30, 2018 . 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 delayed the effective date of the new revenue standard by one year, and the guidance will now be effective as of the Company's first quarter of fiscal 2019. The Company has substantially completed its detailed review of the impact of the guidance on each of its revenue streams. Based on this review, the Company has not currently identified any changes to net income, cash flows or the timing of revenue recognition, although the Company will continue to assess the impact of the guidance through the date of adoption. The Company will also need to review its internal controls and enhance its financial statement disclosures to comply with the new authoritative guidance. The Company expects to adopt the guidance using the modified retrospective method of adoption on October 1, 2018. Under the modified retrospective approach, the cumulative effect of initially applying the new guidance is recognized as an adjustment to the opening balance of retained earnings in the period of adoption.

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 were applied prospectively at the time of adoption.

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 is eligible to be capitalized as part of the cost of inventory or property, plant and equipment while the other components of net periodic pension cost and net periodic postretirement benefit cost are generally not eligible for capitalization, unless allowed by a regulator. The new guidance will be effective as of the Company's first quarter of fiscal 2019. Refer to Note 8 - Retirement Plan and Other Post-Retirement Benefits for the components of the Company's net periodic pension cost and net periodic postretirement benefit cost.

In February 2018, the FASB issued authoritative guidance that allows an entity to elect a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the 2017 Tax Reform Act and requires certain disclosures about stranded tax effects. The new guidance will be effective as of the Company's first quarter of fiscal 2020, with early adoption permitted. The Company anticipates early adoption and is currently awaiting regulatory approval of the reclassification to retained earnings from the FERC for the Company's Pipeline and Storage segment.

Note 2 – Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of June 30, 2018 and September 30, 2017 . 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, 2018				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments [1]	Total [1]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$ 291,994	$ —	$ —	$ —	$ 291,994
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	1,022	—	—	(1,022)	—
Over the Counter Swaps – Gas and Oil	—	28,180	—	(17,567)	10,613
Foreign Currency Contracts	—	155	—	(155)	—
Other Investments:					
Balanced Equity Mutual Fund	37,300	—	—	—	37,300
Fixed Income Mutual Fund	51,201	—	—	—	51,201
Common Stock – Financial Services Industry	2,790	—	—	—	2,790
Hedging Collateral Deposits	2,283	—	—	—	2,283
Total	$ 386,590	$ 28,335	$ —	$ (18,744)	$ 396,181
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$ 1,785	$ —	$ —	$ (1,022)	$ 763
Over the Counter Swaps – Gas and Oil	—	53,305	—	(17,567)	35,738
Foreign Currency Contracts	—	1,666	—	(155)	1,511
Total	$ 1,785	$ 54,971	$ —	$ (18,744)	$ 38,012
Total Net Assets/(Liabilities)	$ 384,805	$ (26,636)	$ —	$ —	$ 358,169

Recurring Fair Value Measures	At fair value as of September 30, 2017				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments [1]	Total [1]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$ 527,978	$ —	$ —	$ —	$ 527,978
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	1,483	—	—	(963)	520
Over the Counter Swaps – Gas and Oil	—	38,977	—	(4,206)	34,771
Foreign Currency Contracts	—	1,227	—	(407)	820
Other Investments:					
Balanced Equity Mutual Fund	37,033	—	—	—	37,033
Fixed Income Mutual Fund	45,727	—	—	—	45,727
Common Stock – Financial Services Industry	3,150	—	—	—	3,150
Hedging Collateral Deposits	1,741	—	—	—	1,741
Total	$ 617,112	$ 40,204	$ —	$ (5,576)	$ 651,740
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$ 963	$ —	$ —	$ (963)	$ —
Over the Counter Swaps – Gas and Oil	—	5,309	—	(4,206)	1,103
Foreign Currency Contracts	—	407	—	(407)	—
Total	$ 963	$ 5,716	$ —	$ (5,576)	$ 1,103
Total Net Assets/(Liabilities)	$ 616,149	$ 34,488	$ —	$ —	$ 650,637

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

Derivative Financial Instruments

At June 30, 2018 and September 30, 2017 , 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 $2.3 million at June 30, 2018 and $1.7 million at September 30, 2017, 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, 2018 and September 30, 2017 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, 2018 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, 2018 , 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 quarters and nine months ended June 30, 2018 and June 30, 2017 , there were no assets or liabilities measured at fair value and classified as Level 3. For the quarters and nine months ended June 30, 2018 and June 30, 2017 , 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, 2018		September 30, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ 2,085,582	$ 2,116,994	$ 2,383,681	$ 2,523,639

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

	At June 30, 2018	At September 30, 2017
Life Insurance Contracts	$ 39,453	$ 39,355
Equity Mutual Fund	37,300	37,033
Fixed Income Mutual Fund	51,201	45,727
Marketable Equity Securities	2,790	3,150
	$ 130,744	$ 125,265

Investments in life insurance contracts are stated at their cash surrender values or net present value. Investments in an equity mutual fund, a fixed income mutual fund and the stock of an insurance company (marketable equity securities) are stated at fair value based on quoted market prices. The gross unrealized gain on the equity mutual fund was $9.6 million at June 30, 2018 and $9.9 million at September 30, 2017 . A sale of shares in the equity mutual fund during the nine months ended June 30, 2018 resulted in $1.5 million of cash proceeds and a realized gain of $0.4 million . The gross unrealized loss on the fixed income mutual fund was $0.6 million at June 30, 2018 and was less than $0.1 million at September 30, 2017. A sale of shares in the fixed income mutual fund during the nine months ended June 30, 2018 resulted in $1.5 million of cash proceeds and a realized loss of less than $0.1 million . The gross unrealized gain on the marketable equity securities was $1.8 million at June 30, 2018 and $2.2 million at September 30, 2017 . The insurance contracts and marketable equity and fixed income securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments. The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment as well as the Energy Marketing segment. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. In addition, the Company also enters into foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. These instruments are accounted for as cash flow hedges. The Company also enters into futures contracts and swaps, which are accounted for as cash flow hedges, to manage the price risk associated with forecasted gas purchases. The Company enters into futures contracts and swaps to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in value of natural gas held in storage. These instruments are accounted for as fair value hedges. The duration of the Company's combined cash flow and fair value commodity hedges does not typically exceed 5 years while the foreign currency forward contracts do not exceed 8 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, 2018 and September 30, 2017 . 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 (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of June 30, 2018 , the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	131.6	Bcf (short positions)
Natural Gas	1.3	Bcf (long positions)
Crude Oil	4,314,000	Bbls (short positions)

As of June 30, 2018 , the Company was hedging a total of $90.8 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts (long positions).

As of June 30, 2018 , the Company had $25.6 million ($20.6 million after tax) of net hedging losses included in the accumulated other comprehensive income (loss) balance. It is expected that $21.9 million ($14.9 million after tax) of unrealized losses will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transaction are recorded in earnings.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended June 30, 2018 and 2017 (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,**	
	2018	2017		2018	2017		2018	2017
Commodity Contracts	$ (35,976)	$ 17,342	Operating Revenue	$ (3,249)	$ 18,600	Operating Revenue	$ (339)	$ 1,040
Commodity Contracts	124	240	Purchased Gas	5	21	Not Applicable	—	—
Foreign Currency Contracts	(1,600)	651	Operation and Maintenance Expense	(527)	(169)	Not Applicable	—	—
Total	$ (37,452)	$ 18,233		$ (3,771)	$ 18,452		$ (339)	$ 1,040

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2018 and 2017 (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,**	
	2018	2017		2018	2017		2018	2017
Commodity Contracts	$ (52,440)	$ 9,382	Operating Revenue	$ 6,125	$ 62,030	Operating Revenue	$ (436)	$ 940
Commodity Contracts	737	(252)	Purchased Gas	952	(1,938)	Not Applicable	—	—
Foreign Currency Contracts	(3,831)	699	Operation and Maintenance Expense	(1,500)	(451)	Not Applicable	—	—
Total	$ (55,534)	$ 9,829		$ 5,577	$ 59,641		$ (436)	$ 940

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, 2018 , the Company's Energy Marketing segment had fair value hedges covering approximately 24.8 Bcf (24.2 Bcf of fixed price sales commitments and 0.6 Bcf of commitments related to the withdrawal of storage gas). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Derivatives in Fair Value Hedging Relationships	Location of Gain or (Loss) on Derivative and Hedged Item Recognized in the Consolidated Statement of Income	Amount of Gain or (Loss) on Derivative Recognized in the Consolidated Statement of Income for the Nine Months Ended June 30, 2018 (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, 2018 (In Thousands)
Commodity Contracts	Operating Revenues	$ (824)	$ 824
Commodity Contracts	Purchased Gas	$ (223)	$ 223
		$ (1,047)	**$ 1,047**

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 eighteen counterparties of which three are in a net gain position. On average, the Company had $3.5 million of credit exposure per counterparty in a gain position at June 30, 2018 . The maximum credit exposure per counterparty in a gain position at June 30, 2018 was $6.7 million . As of June 30, 2018 , 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, 2018 , fifteen of the eighteen 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, 2018 , the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $10.6 million according to the Company's internal model (discussed in Note 2 — Fair Value Measurements). At June 30, 2018 , the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $31.9 million according to the Company's internal model. 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, 2018 .

For its exchange traded futures contracts, the Company was required to post $2.3 million in hedging collateral deposits as of June 30, 2018 . 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.

Note 4 - Income Taxes

The effective tax rate for the quarters ended June 30, 2018 and June 30, 2017 was 23.3% and 37.4% , respectively. The difference was primarily a result of the lower statutory rate of 24.5% under the 2017 Tax Reform Act (as discussed below). The effective tax rate was negative 7.2% for the nine months ended June 30, 2018 and 37.9% for the nine months ended June 30, 2017 . The difference was a result of the impact of the one-time remeasurement of the deferred income tax liability and a lower statutory rate of 24.5% under the 2017 Tax Reform Act.

On December 22, 2017, federal tax legislation referred to as the "Tax Cuts and Jobs Act" (the 2017 Tax Reform Act) was enacted. The 2017 Tax Reform Act significantly changed the taxation of business entities and included a reduction in the corporate federal income tax rate from 35% to a blended 24.5% for fiscal 2018 and 21% for fiscal 2019 and beyond. The changes had a material impact on the financial statements in the quarter and nine months ended June 30, 2018. The Company's deferred income taxes were remeasured based upon the new tax rates. For the non-rate regulated activities through the nine months ended June 30, 2018, the change in deferred income taxes of $107.0 million was recorded as a reduction to income tax expense. For the Company's rate regulated activities, the reduction in deferred income taxes of $336.7 million was recorded as a decrease to Recoverable Future Taxes of $65.7 million and an increase to Taxes Refundable to Customers of $271.0 million . The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes are to be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred income taxes will be determined by the federal and state regulatory agencies. The Company is currently reviewing guidance issued by regulatory agencies in the jurisdictions in which it operates. For further discussion, refer to Note 9 - Regulatory Matters.

The 2017 Tax Reform Act also repealed the corporate alternative minimum tax (AMT) and provides that the Company's existing AMT credit carryovers are refundable beginning in fiscal 2019. As of June 30, 2018 , the Company had $90.2 million of AMT credit carryovers that are expected to be utilized or refunded between fiscal 2019 and fiscal 2022. During the quarter ended March 31, 2018, the Company recorded a $4.0 million estimate of the potential sequestration of the refunds of the AMT credits.

The SEC issued guidance in Staff Accounting Bulletin 118 (SAB 118) which provides for up to a one year period (the measurement period) in which to complete the required analysis and income tax accounting for the 2017 Tax Reform Act. The Company has determined a reasonable estimate for the measurement of the changes in deferred income taxes (noted above), which have been reflected as provisional amounts in the June 30, 2018 financial statements. The final determination of the impact of the income tax effects of these items will require additional analysis and further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Treasury regulations, state income tax guidance, federal/state regulatory guidance, and possible technical corrections. The Company expects to finalize the analysis within SAB 118's one-year measurement period based upon existing guidance at that time. Any subsequent guidance will be accounted for in the period issued.

Note 5 - Capitalization

Common Stock. During the nine months ended June 30, 2018 , the Company issued 68,619 original issue shares of common stock as a result of SARs exercises, 71,918 original issue shares of common stock for restricted stock units that vested and 79,079 original issue shares of common stock for performance shares that vested. In addition, the Company issued 138,997 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 75,745 original issue shares of common stock for the Company's 401(k) plans. The Company also issued 20,721 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, 2018 . Holders of stock-based compensation awards will often tender shares of common stock to the Company for payment of applicable withholding taxes. During the nine months ended June 30, 2018 , 54,329 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

Current Portion of Long-Term Debt. Current Portion of Long-Term Debt at June 30, 2018 consists of $250.0 million of 8.75% notes that mature in May 2019. Current Portion of Long-Term Debt at September 30, 2017 consisted of $300.0 million of 6.50% notes that were scheduled to mature in April 2018. The Company redeemed the 6.50% notes on October 18, 2017 for $307.0 million , plus accrued interest. The call premium was recorded to Unamortized Debt Expense on the Consolidated Balance Sheet in October 2017.

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, 2018 , the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately $7.7 million , which includes a $4.2 million estimated minimum liability to remediate a former manufactured gas plant site located in New York. In March 2018, the NYDEC issued a Record of Decision for this New York site and the minimum liability reflects the remedy selected in the Record of Decision. The Company's liability for such clean-up costs has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at June 30, 2018 . The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 4 years and 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. The Company also has pending with FERC a proceeding asserting, among other things, that the NYDEC exceeded the reasonable and statutory time frames to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. In light of these pending legal actions, the Company has not yet determined a 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, 2018 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 $75.6 million at June 30, 2018 . 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 2017 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income. There have not been any changes in the basis of segmentation nor in the basis of measuring segment profit or loss from those used in the Company's 2017 Form 10-K. A listing of segment assets at June 30, 2018 and September 30, 2017 is shown in the tables below.

Quarter Ended June 30, 2018 (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	$135,828	$51,363	$(31)	$128,628	$25,460	$341,248	$1,496	$168	$342,912
Intersegment Revenues	$—	$22,496	$27,908	$3,519	$512	$54,435	$—	$(54,435)	$—
Segment Profit: Net Income (Loss)	$27,817	$20,723	$11,566	$3,930	$(190)	$63,846	$297	$(1,118)	$63,025

Nine Months Ended June 30, 2018 (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	$421,381	$158,387	$41	$599,495	$119,739	$1,299,043	$3,824	$606	$1,303,473
Intersegment Revenues	$—	$67,524	$79,404	$11,401	$589	$158,918	$—	$(158,918)	$—
Segment Profit: Net Income (Loss)	$161,052	$81,909	$68,736	$58,283	$1,434	$371,414	$(214)	$(17,673)	$353,527

(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, 2018	$1,591,783	$1,763,620	$534,086	$1,904,189	$51,778	$5,845,456	$77,879	$50,768	$5,974,103
At September 30, 2017	$1,407,152	$1,929,788	$580,051	$2,013,123	$60,937	$5,991,051	$76,861	$35,408	$6,103,320

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

Note 8 – Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

	Retirement Plan		Other Post-Retirement Benefits	
Three Months Ended June 30,	2018	2017	2018	2017
Service Cost	$ 2,480	$ 2,992	$ 458	$ 612
Interest Cost	8,252	9,596	3,700	4,752
Expected Return on Plan Assets	(15,429)	(14,929)	(7,871)	(7,865)
Amortization of Prior Service Cost (Credit)	235	264	(107)	(107)
Amortization of Losses	9,301	10,672	2,639	4,604
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	712	(3,193)	3,386	1,302
Net Periodic Benefit Cost	$ 5,551	$ 5,402	$ 2,205	$ 3,298

	Retirement Plan		Other Post-Retirement Benefits	
Nine Months Ended June 30,	2018	2017	2018	2017
Service Cost	$ 7,441	$ 8,977	$ 1,373	$ 1,837
Interest Cost	24,754	28,788	11,101	14,256
Expected Return on Plan Assets	(46,286)	(44,788)	(23,612)	(23,594)
Amortization of Prior Service Cost (Credit)	703	793	(322)	(322)
Amortization of Losses	27,904	32,015	7,918	13,811
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	8,926	3,577	13,243	6,404
Net Periodic Benefit Cost	$ 23,442	$ 29,362	$ 9,701	$ 12,392

(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, 2018 , the Company contributed $27.6 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $2.7 million to its VEBA trusts for its other post-retirement benefits. In the remainder of 2018 , the Company may contribute up to $5.0 million to the Retirement Plan and the Company expects to contribute approximately $0.2 million to its VEBA trusts.

Note 9 – Regulatory Matters

New York Jurisdiction

Distribution Corporation's current delivery rates in its New York jurisdiction were approved by the NYPSC in an order issued on April 20, 2017 with rates becoming effective May 1, 2017. On July 28, 2017, Distribution Corporation filed an appeal with New York State Supreme Court, Albany County, seeking review of the Order. The appeal contends that portions of the Order should be invalidated because they fail to meet the applicable legal standard for agency decisions. On December 11, 2017, the appeal was transferred to the Supreme Court, Appellate Division, Third Department. The Company cannot predict the outcome of the appeal at this time.

On December 29, 2017, the NYPSC issued an order instituting a proceeding to study the potential effects of the enactment of the 2017 Tax Reform Act on the tax expenses and liabilities of New York utilities. The order stated the NYPSC’s intent to ensure that the net benefits resulting from tax reform were preserved for ratepayers. Pursuant to the order, a technical conference was held with the utilities in February 2018, and the New York Department of Public Service Staff subsequently issued a proposal for accounting and ratemaking treatment of the tax changes. The NYPSC has not yet acted on this proposal. On June 4, 2018, Distribution Corporation filed a petition with the NYPSC regarding Distribution Corporation's proposed disposition of net federal income tax savings resulting from the 2017 Tax Reform Act seeking authorization to 1) implement a customer refund program to return the net effect of the recent federal income tax rate reduction to Distribution Corporation's customers and 2) allow Distribution Corporation recovery for the improvements to the Company's imputed equity ratio directly resulting from the recent federal tax rate reduction. Distribution Corporation has requested the NYPSC to act on its petition in advance of the 2018-2019 winter heating season, but cannot predict the timing or outcome of its petition at this time. Refer to Note 4 - Income Taxes for further discussion of the 2017 Tax Reform Act.

Pennsylvania Jurisdiction

Distribution Corporation's Pennsylvania jurisdiction delivery rates are being charged to customers in accordance with a rate settlement approved by the PaPUC. The rate settlement does not specify any requirement to file a future rate case.

By Secretarial Letter issued February 12, 2018, the PaPUC initiated a proceeding to determine the effects of the 2017 Tax Reform Act on the tax liabilities of PaPUC-regulated public utilities for 2018 and future years and the feasibility of reflecting such impacts on the rates charged to utility ratepayers. On March 15, 2018, the PaPUC issued a Temporary Rates Order making Distribution Corporation's rates (along with the rates of other Pennsylvania public utilities not presently in a general rate increase proceeding) temporary for a period of six months. On May 17, 2018, the PaPUC issued an Order to Distribution Corporation, superceding and canceling Distribution Corporation's temporary rates filed pursuant to the March 15, 2018 order and requiring that Distribution Corporation file a tariff supplement establishing temporary rates to implement refunds of 2.2% on customer rates beginning July 1, 2018. Distribution Corporation has filed the necessary tariff supplement to implement such refunds effective July 1, 2018. The May 17, 2018 PaPUC Order provides for a number of options regarding the permanent or temporary status of these rates and associated cost and rate deferral options. The Company is currently evaluating these specific options. Refer to Note 4 - Income Taxes for further discussion of the 2017 Tax Reform Act.

FERC Jurisdiction

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.

Empire filed a Section 4 rate case on June 29, 2018, proposing rate increases to be effective August 1, 2018. The proposed rates reflect an annual cost of service of $71.5 million , a rate base of $246.8 million and a proposed return on equity of 14% . The proposed rate increases are expected to be suspended, with an effective date of January 1, 2019, subject to refund. Lower storage rates are expected to be effective August 1, 2018. If the proposed rate increases finally approved at the end of the proceeding exceed the rates that were in effect at June 29, 2018, but are less than rates put into effect subject to refund on January 1, 2019, Empire would be required to refund the difference between the rates collected subject to refund and the final approved rates, with interest at the FERC-approved rate. If the rates approved at the end of the proceeding are lower than the rates in effect at June 29, 2018, such lower rates will become effective prospectively from the date of the applicable FERC order, and refunds with interest will be limited to the difference between the rates collected subject to refund and the rates in effect at June 29, 2018.

On July 18, 2018, the FERC issued a Final Rule in RM18-11-000, et. al, (Order No. 849) which requires pipelines to file a new form isolating the tax impact to each pipeline and also to make an election regarding the action the pipelines will take to address the lower tax rates, one of which is filing a Section 4 rate proceeding or Notice of Inquiry regarding treatment of accumulated deferred income taxes and other tax issues associated with the 2017 Tax Reform Act. Supply Corporation will be required to address the Order by December 6, 2018. At this point, the Company cannot predict the outcome of any action proposed pursuant to the Order. Refer to Note 4 - Income Taxes for further discussion of the 2017 Tax Reform Act.

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 primarily in the Marcellus and Utica Shale. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian basin to markets in Canada and the eastern United States. The Company's efforts in this regard are not limited to affiliated projects. The Company has also been designing and building pipeline projects for the transportation of natural gas for non-affiliated natural gas producers in the Appalachian basin. 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, 2018 compared to the quarter and nine months ended June 30, 2017, the Company experienced an increase in earnings of $3.3 million and $115.6 million, respectively. As a result of the 2017 Tax Reform Act, the effective tax rates for the quarter and nine months ended June 30, 2018 of 23.3% and negative 7.2%, respectively, reflect a lower statutory rate of 24.5%. The effective tax rate for the nine months ended June 30, 2018 also reflects the impact of a remeasurement of the Company's accumulated deferred income tax liability based upon the new tax rates, recorded as a $107.0 million reduction to income tax expense. The Company's non-regulated operations are benefiting from the 2017 Tax Reform Act while the regulated operations anticipate future rate reductions. In this regard, the Company filed a petition on June 4, 2018 with the NYPSC regarding Distribution Corporation's proposed disposition of net federal income tax savings in Distribution Corporation's New York jurisdiction. In Distribution Corporation's Pennsylvania jurisdiction, the Company received an order from the PaPUC requiring the establishment of temporary rates to implement refunds of 2.2% on customer rates beginning July 1, 2018. For further discussion of the impact of the 2017 Tax Reform Act to the Company, refer to Rate and Regulatory Matters below and to Item 1 at Note 4 — Income Taxes. 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). 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. The Company also has pending with FERC a proceeding asserting, among other things, that the NYDEC exceeded the reasonable and statutory time frames to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. The Company remains committed to the project. Approximately $75.6 million in costs have been incurred on this project through June 30, 2018, 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.

While legal proceedings continue on Northern Access 2016, the Company continues to pursue development projects to expand its Pipeline and Storage segment. One project on Empire's system, referred to as the Empire North Project, would allow for the transportation of 205,000 Dth per day of additional shale supplies from interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline, and the TGP 200 Line. The Empire North Project has a projected in-service date in the second half of fiscal 2020 and an estimated cost of approximately $145 million. Another project on Supply Corporation's system, referred to as the FM 100 Project, is currently in the pre-filing process at FERC and will upgrade 1950's era pipeline in northwestern Pennsylvania and create approximately 300,000 Dth per day of additional capacity on Supply Corporation's system in Pennsylvania from a receipt point with NFG Midstream Clermont, LLC in McKean County to the Transcontinental Gas Pipe Line Company, LLC system at Leidy, Pennsylvania. The preliminary cost estimate for this project is approximately $280 million. These and other projects are discussed in more detail in the Capital Resources and Liquidity section that follows.

From a financing perspective, in September 2017, the Company issued $300.0 million of 3.95% notes due in September 2027. The proceeds of the debt issuance were used for the October 2017 redemption of $300.0 million of the Company's 6.50% notes that were scheduled to mature in April 2018. The Company expects to use cash on hand and cash from operations to meet its capital expenditure needs for the remainder of fiscal 2018 and may issue short-term and/or long-term debt during fiscal 2018 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 2017 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, 2018 , the ceiling exceeded the book value of the oil and gas properties by approximately $462.3 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, 2018 , based on posted Midway Sunset prices, was $57.50 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, 2018 , based on the quoted Henry Hub spot price for natural gas, was $2.92 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, 2018 . 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, 2018 (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, 2018 , if crude oil prices were $5 per Bbl lower than the average prices used at June 30, 2018 , 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, 2018 (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	$ 304.9	$ 430.2	$ 272.9

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 2017 Form 10-K.

2017 Tax Reform Act. On December 22, 2017, the tax legislation referred to as the “Tax Cuts and Jobs Act” (the 2017 Tax Reform Act) was enacted. The 2017 Tax Reform Act significantly changes the taxation of business entities and includes a reduction in the corporate federal income tax rate from 35% to a blended 24.5% for fiscal 2018 and 21% for fiscal 2019 and beyond. As a fiscal year taxpayer, the Company is required to use a blended tax rate for fiscal 2018.

The Company has determined a reasonable estimate under SAB 118 for the measurement of the changes in deferred income taxes in the June 30, 2018 financial statements. The final determination of the impact of the income tax effects of these items will require additional analysis and further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Treasury regulations, state income tax guidance, federal and state regulatory guidance, and possible technical corrections. The Company expects to finalize the analysis within SAB 118's one-year measurement period based upon existing guidance at that time. Any subsequent guidance will be accounted for in the period issued. For further discussion of the impact of the 2017 Tax Reform Act to the Company, refer to Item 1 at Note 4 — Income Taxes.

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $63.0 million for the quarter ended June 30, 2018 compared to earnings of $59.7 million for the quarter ended June 30, 2017 . The increase in earnings of $3.3 million is primarily a result of higher earnings in the Pipeline and Storage segment, Gathering segment and All Other category, as well as a lower loss in the Energy Marketing segment. Lower earnings in the Exploration and Production segment and Utility segment, as well as a loss in the Corporate category, partially offset these increases.

The Company's earnings were $353.5 million for the nine months ended June 30, 2018 compared to earnings of $237.9 million for the nine months ended June 30, 2017 . The increase in earnings of $115.6 million is primarily a result of higher earnings in the Exploration and Production segment, Gathering segment, Pipeline and Storage segment and Utility segment, as well as a lower loss in the All Other category. Lower earnings in the Energy Marketing segment, as well as a loss in the Corporate category, partially offset these increases.

The Company's earnings for the nine months ended June 30, 2018 include a $107.0 million remeasurement of accumulated deferred income taxes and a lower statutory rate of 24.5% as a result of the 2017 Tax Reform Act, as discussed above. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Exploration and Production	$ 27,817	$ 30,123	$ (2,306)	$ 161,052	$ 98,972	$ 62,080
Pipeline and Storage	20,723	16,031	4,692	81,909	54,656	27,253
Gathering	11,566	10,107	1,459	68,736	31,373	37,363
Utility	3,930	4,348	(418)	58,283	51,103	7,180
Energy Marketing	(190)	(564)	374	1,434	2,122	(688)
Total Reportable Segments	63,846	60,045	3,801	371,414	238,226	133,188
All Other	297	(98)	395	(214)	(498)	284
Corporate	(1,118)	(233)	(885)	(17,673)	178	(17,851)
Total Consolidated	$ 63,025	$ 59,714	$ 3,311	$ 353,527	$ 237,906	$ 115,621

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Gas (after Hedging)	$ 99,621	$ 113,776	$ (14,155)	$ 303,732	$ 357,158	$ (53,426)
Oil (after Hedging)	35,312	35,504	(192)	114,190	110,620	3,570
Gas Processing Plant	957	704	253	3,095	2,393	702
Other	(62)	1,177	(1,239)	364	1,475	(1,111)
	$ 135,828	$ 151,161	$ (15,333)	$ 421,381	$ 471,646	$ (50,265)

Production Volumes

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Gas Production *(MMcf)*						
Appalachia	40,444	37,904	2,540	117,261	118,517	(1,256)
West Coast	526	733	(207)	1,896	2,246	(350)
Total Production	40,970	38,637	2,333	119,157	120,763	(1,606)
Oil Production *(Mbbl)*						
Appalachia	1	1	—	3	3	—
West Coast	600	669	(69)	1,934	2,062	(128)
Total Production	601	670	(69)	1,937	2,065	(128)

Average Prices

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Average Gas Price/Mcf						
Appalachia	$ 2.30	$ 2.58	$ (0.28)	$ 2.37	$ 2.55	$ (0.18)
West Coast	$ 4.41	$ 3.39	$ 1.02	$ 4.62	$ 4.07	$ 0.55
Weighted Average	$ 2.32	$ 2.59	$ (0.27)	$ 2.40	$ 2.58	$ (0.18)
Weighted Average After Hedging	$ 2.43	$ 2.94	$ (0.51)	$ 2.55	$ 2.96	$ (0.41)
Average Oil Price/Bbl						
Appalachia	$ 64.37	$ 48.34	$ 16.03	$ 55.06	$ 48.85	$ 6.21
West Coast	$ 71.53	$ 45.63	$ 25.90	$ 64.69	$ 45.71	$ 18.98
Weighted Average	$ 71.52	$ 45.64	$ 25.88	$ 64.68	$ 45.76	$ 18.92
Weighted Average After Hedging	$ 58.74	$ 53.02	$ 5.72	$ 58.96	$ 53.58	$ 5.38

2018 Compared with 2017

Operating revenues for the Exploration and Production segment decreased $15.3 million for the quarter ended June 30, 2018 as compared with the quarter ended June 30, 2017. Gas production revenue after hedging decreased $14.2 million primarily due to a $0.51 per Mcf decrease in the weighted average price of gas after hedging partially offset by an increase in gas production, due to higher net production from new Marcellus and Utica wells completed and connected to sales in the Western and Eastern Development Areas during the past year. Oil production revenue after hedging decreased $0.2 million due to a decrease in crude oil production, due largely to the expected reduction in California production after the sale of Seneca's Sespe properties in the current quarter, offset by a $5.72 per Bbl increase in the weighted average price of oil after hedging. In addition, other revenue decreased $1.2 million primarily due to positive mark-to-market adjustments related to hedging ineffectiveness that occurred during the quarter ended June 30, 2017. These decreases to operating revenues were slightly offset by an increase in gas processing plant revenue of $0.3 million.

Operating revenues for the Exploration and Production segment decreased $50.3 million for the nine months ended June 30, 2018 as compared with the nine months ended June 30, 2017. Gas production revenue after hedging decreased $53.4 million primarily due to a $0.41 per Mcf decrease in the weighted average price of gas after hedging coupled with a decrease in gas production. The decrease in production was primarily due to natural declines from Marcellus wells in the Eastern Development Area. This was partially offset by production increases in the Western Development Area from new Marcellus and Utica wells coupled with a decrease in price-related curtailments during the nine months ended June 30, 2018 compared to the nine months ended June 30, 2017. In addition, other revenue decreased $1.1 million primarily due to positive mark-to-market adjustments related to hedging ineffectiveness that occurred during the nine months ended June 30, 2017. These decreases to operating revenues were partially offset by an increase in oil production revenue after hedging of $3.6 million. The increase in oil production revenue was due to a $5.38 per Bbl increase in the weighted average price of oil after hedging, which was partially offset by a decrease in crude oil production. The decrease in crude oil production in the West Coast region was due largely to lower production from Seneca's Sespe properties. Seneca completed a sale of its Sespe properties on May 1, 2018, which lowered crude oil production for the nine months ended June 30, 2018. In addition, Seneca temporarily shut-in production at its Sespe field in the first quarter of fiscal 2018 in response to the wildfires occurring in Ventura County, California, which also contributed to lower crude oil production for the nine months ended June 30, 2018. Additionally, gas processing plant revenue increased $0.7 million.

The Exploration and Production segment's earnings for the quarter ended June 30, 2018 were $27.8 million, a decrease of $2.3 million when compared with earnings of $30.1 million for the quarter ended June 30, 2017. This decrease in earnings was primarily due to lower natural gas prices after hedging ($13.7 million), lower crude oil production ($2.4 million), higher depletion expense ($2.5 million) and higher other operating expenses ($0.6 million). The increase in depletion expense was due to an increase in capitalized costs and an increase in production, partially offset by an increase in reserves (an increase in reserves lowers the per Mcf/barrel depletion rate). The increase in other operating expenses was primarily due to an increase in personnel costs and legal expenses. These factors, which decreased earnings during the quarter ended June 30, 2018 compared to the quarter ended June 30, 2017, were partially offset by an increase in earnings due to the impact of the 2017 Tax Reform Act, which reduced the Company's federal tax rate and lowered income tax expense in the current quarter ($6.2 million). In addition, earnings benefited from higher crude oil prices after hedging ($2.2 million), higher natural gas production ($4.5 million), lower production expenses ($2.0 million) and lower income tax expense, excluding the impact of the 2017 Tax Reform Act ($1.7 million). The decrease in production expense was largely due to the aforementioned sale of Seneca's Sespe properties in the current quarter, coupled with decreased well repairs and workovers and decreased steam fuel costs associated with operating wells in the West Coast region. Additionally, production expense decreased in the Appalachian region due to the transfer of compression facilities in Tioga County, Pa., to the Company's Gathering segment in the second quarter of fiscal 2018 and the sale of shale appraisal test wells located in the non-core areas of the Western Development Area in the fourth quarter of fiscal 2017, partially offset by increased gathering costs due to higher production. The decrease in income tax expense, excluding the impact of the 2017 Tax Reform Act, was largely due to lower state income taxes.

The Exploration and Production segment's earnings for the nine months ended June 30, 2018 were $161.1 million, an increase of $62.1 million when compared with earnings of $99.0 million for the nine months ended June 30, 2017. The increase in earnings was primarily attributable to the impact of the 2017 Tax Reform Act, which resulted in a remeasurement of accumulated deferred income taxes ($76.5 million) and reduced the Company's federal tax rate resulting in lower income tax expense on current year earnings ($17.4 million). In addition, earnings benefited from higher crude oil prices after hedging ($6.8 million), lower production expenses ($1.2 million), and lower income tax expense, excluding the impact of the 2017 Tax Reform Act ($3.9 million). The decrease in production expense was largely due to the aforementioned sale of Seneca's Sespe properties in the current quarter combined with a decline in production expense in the Appalachian region. The decrease in production expense in the Appalachian region was primarily due to the transfer of compression facilities to the Company's Gathering segment and the sale of shale appraisal test wells (both of which are discussed above), as well as a decline in gathering costs as a result of lower production. These decreases to production expense were partially offset by increased well repairs and workovers, steam fuel costs and repairs and maintenance associated with operating wells in the West Coast region. The decrease in income tax expense, excluding the impact of the 2017 Tax Reform Act, was largely due to lower state income taxes. These factors, which contributed to increased earnings during the nine months ended June 30, 2018 compared to the nine months ended June 30, 2017, were partially offset by lower natural gas prices after hedging ($31.6 million), lower natural gas production ($3.1 million), lower crude oil production ($4.4 million), higher depletion expense ($3.5 million) and higher other operating expenses ($1.6 million). The increase in depletion expense was due to an increase in capitalized costs partially offset by a decrease in production and an increase in reserves. The increase in other operating expenses was primarily due to an increase in personnel costs and legal expenses.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Firm Transportation	$ 54,227	$ 53,753	$ 474	$ 168,546	$ 167,851	$ 695
Interruptible Transportation	380	353	27	1,108	1,391	(283)
	54,607	54,106	501	169,654	169,242	412
Firm Storage Service	18,951	17,391	1,560	55,316	52,468	2,848
Interruptible Storage Service	3	—	3	23	12	11
Other	298	195	103	918	879	39
	$ 73,859	$ 71,692	$ 2,167	$ 225,911	$ 222,601	$ 3,310

Pipeline and Storage Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Firm Transportation	177,071	183,451	(6,380)	583,452	587,598	(4,146)
Interruptible Transportation	1,107	1,060	47	3,153	5,078	(1,925)
	178,178	184,511	(6,333)	586,605	592,676	(6,071)

2018 Compared with 2017

Operating revenues for the Pipeline and Storage segment increased $2.2 million for the quarter ended June 30, 2018 as compared with the quarter ended June 30, 2017 . The increase in operating revenues was primarily due to demand charges for transportation service from Supply Corporation's Line D Expansion, which was placed in service on November 1, 2017, an increase in reservation charges for storage service from new storage contracts as a result of Supply Corporation's acquisition of the remaining interest in a jointly owned storage field and an increase in both transportation and storage revenues due to Supply Corporation's greenhouse gas and pipeline safety surcharge effective November 1, 2017. Partially offsetting these increases was a decline in transportation revenues due to a decline in demand charges for transportation services as a result of contract terminations.

Operating revenues for the Pipeline and Storage segment increased $3.3 million for the nine months ended June 30, 2018 as compared with the nine months ended June 30, 2017 . The increase in operating revenues was primarily due to demand charges for transportation service from Supply Corporation's Line D Expansion, which was placed in service on November 1, 2017, an increase in reservation charges for storage service from new storage contracts as a result of Supply Corporation's acquisition of the remaining interest in a jointly owned storage field and an increase in both transportation and storage revenues due to Supply Corporation's greenhouse gas and pipeline safety surcharge effective November 1, 2017. Partially offsetting these increases was a decline in transportation revenues due partially to an additional 2% reduction in Supply Corporation's rates effective November 1, 2016, which was required by the rate case settlement approved by FERC on November 13, 2015, and a decline in demand charges for transportation services as a result of contract terminations.

Transportation volume for the quarter ended June 30, 2018 decreased by 6.3 Bcf from the prior year’s quarter. For the nine months ended June 30, 2018 , transportation volume decreased by 6.1 Bcf from the prior year's nine -month period ended June 30, 2017 . The decrease in transportation volume for the quarter and nine-month period primarily reflects a reduction in capacity utilization by certain contract shippers combined with contract terminations. 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, 2018 were $20.7 million, an increase of $4.7 million when compared with earnings of $16.0 million for the quarter ended June 30, 2017 . The increase in earnings was primarily due to lower income tax expense ($3.0 million) combined with the earnings impact of higher transportation and storage revenues of $1.3 million, as discussed above, and a decrease in interest expense ($0.5 million). Income tax expense was lower due to the current period earnings impact of the change in the federal tax rate from 35% to a blended rate of 24.5% for fiscal 2018 as a result of the 2017 Tax Reform Act. The decrease in interest expense was largely due to lower intercompany long-term borrowing interest rates for the Pipeline and Storage segment. These earnings increases were slightly offset by a decrease in the allowance for funds used during construction (equity component) of $0.1 million which reflects the impact of a decrease in expansion projects currently in progress compared to the previous year's third quarter.

The Pipeline and Storage segment's earnings for the nine months ended June 30, 2018 were $81.9 million, an increase of $27.2 million when compared with earnings of $54.7 million for the nine months ended June 30, 2017 . The increase in earnings was primarily due to lower income tax expense ($24.1 million) combined with the earnings impact of higher transportation and storage revenues of $2.1 million, as discussed above, lower operating expenses ($2.3 million) and a decrease in interest expense ($1.1 million). Income tax expense was lower due to the remeasurement of accumulated deferred income taxes in the quarter ended December 31, 2017 ($14.1 million) combined with the current period earnings impact of the change in the federal tax rate from 35% to a blended rate of 24.5% for fiscal 2018 ($10.0 million), both a result of the 2017 Tax Reform Act. The decrease in operating expenses primarily reflects lower pension and other post-retirement benefit costs partially offset by an increase in pipeline integrity program expenses, increase in compressor station costs and increased personnel costs. The decrease in interest expense was largely due to lower intercompany long-term borrowing interest rates for the Pipeline and Storage segment. These earnings contributors were slightly offset by an increase in depreciation expense ($1.1 million), an increase in property taxes ($0.4 million) and a decrease in the allowance for funds used during construction (equity component) of $0.7 million. The increase in depreciation expense was due to incremental depreciation expense related to expansion projects that were placed in service within the last year combined with the non-recurrence of a reduction to depreciation expense recorded in the quarter ended December 31, 2016 to reflect a reduction in depreciation rates retroactive to July 1, 2016 in accordance with Empire's rate case settlement. The FERC issued an order approving the settlement on December 13, 2016. The decrease in allowance for funds used during construction reflects the impact of a decrease in expansion projects currently in progress compared to the previous year's nine-month period.

Looking ahead, the Pipeline and Storage segment expects transportation revenues to be negatively impacted in fiscal 2019 in an amount up to approximately $14 million as a result of an Empire system transportation contract reaching its termination date in December 2018. The Company does not expect to renew the contract at existing rates given a change in market dynamics.

Gathering

Gathering Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Gathering	$ 27,908	$ 26,853	$ 1,055	$ 79,404	$ 82,629	$ (3,225)
Processing and Other Revenues	(31)	34	(65)	41	86	(45)
	$ 27,877	$ 26,887	$ 990	$ 79,445	$ 82,715	$ (3,270)

Gathering Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Gathered Volume - (MMcf)	51,392	48,838	2,554	145,928	150,005	(4,077)

2018 Compared with 2017

Operating revenues for the Gathering segment increased $1.0 million for the quarter ended June 30, 2018 as compared with the quarter ended June 30, 2017. Midstream Company's gathering systems at Covington, Trout Run, Clermont and Wellsboro had a combined revenue increase of $1.3 million and a combined increase in gathered volume of 2.9 Bcf quarter over quarter. The 2.9 Bcf increase in gathered volume can be attributed to a net increase in Seneca's production quarter over quarter. This was partially offset by a $0.2 million decrease in gathering revenues and a 0.3 Bcf decrease in gathered volume quarter over quarter for the Mt. Jewett, Owls Nest and Tionesta gathering systems, which were sold effective February 1, 2018.

Operating revenues for the Gathering segment decreased $3.3 million for the nine months ended June 30, 2018 as compared with the nine months ended June 30, 2017, which was driven by a 4.1 Bcf net decrease in gathered volume due mostly to lower production from Seneca. Midstream Company experienced a 4.2 Bcf decrease in gathered volume at its Trout Run gathering system, a 2.2 Bcf decrease in gathered volume at its Wellsboro gathering system and a 0.7 Bcf decrease in gathered volume at its Covington gathering system. These decreases were partially offset by a 3.6 Bcf increase in gathered volume at the Clermont gathering system. The sale of the gathering systems discussed above also led to a 0.6 Bcf decline in gathered volume.

The Gathering segment's earnings for the quarter ended June 30, 2018 were $11.6 million, an increase of $1.5 million when compared with earnings of $10.1 million for the quarter ended June 30, 2017. The increase in earnings was primarily attributable to the impact of the 2017 Tax Reform Act, which reduced the Company's federal tax rate and lowered income tax expense in the current quarter by $2.4 million. In addition, earnings benefited from higher gathering revenue ($0.7 million), as discussed above. The increase in revenue was offset by higher operating expense ($1.2 million) and higher depreciation expense ($0.2 million). The increase in operating expenses was due largely to the operation of new compression facilities along the Covington gathering system that were acquired from Seneca in March 2018, an increase in facilities and maintenance activity at the Clermont gathering system and a loss recognized on the sale of pipe materials.

The Gathering segment's earnings for the nine months ended June 30, 2018 were $68.7 million, an increase of $37.3 million when compared with earnings of $31.4 million for the nine months ended June 30, 2017. The increase in earnings was primarily attributable to the impact of the 2017 Tax Reform Act, which resulted in a remeasurement of accumulated deferred income taxes ($34.5 million) and reduced the Company's federal tax rate resulting in lower income tax expense on current year earnings ($7.1 million). These earnings increases were offset by lower gathering revenue ($2.1 million), as discussed above, higher operating expenses ($1.3 million) and higher depreciation expense ($0.5 million). The increase in operating expenses was due largely to the operation of the compression facilities at Covington acquired in the current year, an increase in facilities and maintenance activity at the Clermont gathering system, and a loss recognized on the sale of pipe materials. Depreciation expense decreased due to higher plant balances, primarily in Clermont.

Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Retail Sales Revenues:						
Residential	$ 93,560	$ 85,627	$ 7,933	$ 435,388	$ 383,604	$ 51,784
Commercial	10,809	11,045	(236)	61,119	53,118	8,001
Industrial	890	547	343	3,590	2,082	1,508
	105,259	97,219	8,040	500,097	438,804	61,293
Transportation	25,070	26,033	(963)	113,224	111,701	1,523
Off-System Sales	—	—	—	359	3,982	(3,623)
Other	1,818	2,039	(221)	(2,784)	7,646	(10,430)
	$ 132,147	$ 125,291	$ 6,856	$ 610,896	$ 562,133	$ 48,763

Utility Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Retail Sales:						
Residential	10,052	8,105	1,947	56,468	48,817	7,651
Commercial	1,525	1,170	355	8,621	7,373	1,248
Industrial	128	48	80	559	282	277
	11,705	9,323	2,382	65,648	56,472	9,176
Transportation	15,348	13,799	1,549	66,398	60,453	5,945
Off-System Sales	—	—	—	141	1,295	(1,154)
	27,053	23,122	3,931	132,187	118,220	13,967

Degree Days

				Percent Colder (Warmer) Than	
Three Months Ended June 30,	Normal	2018	2017	Normal [1]	Prior Year [1]
Buffalo	912	873	767	(4.3)%	13.8%
Erie	871	825	705	(5.3)%	17.0%
Nine Months Ended June 30,					
Buffalo	6,455	6,308	5,599	(2.3)%	12.7%
Erie	6,023	5,929	5,082	(1.6)%	16.7%

(1) Percents compare actual 2018 degree days to normal degree days and actual 2018 degree days to actual 2017 degree days.

2018 Compared with 2017

Operating revenues for the Utility segment increased $6.9 million for the quarter ended June 30, 2018 as compared with the quarter ended June 30, 2017. The increase largely resulted from an $8.0 million increase in retail gas sales revenues. The increase in retail gas sales revenue was largely a result of higher volumes (due primarily to colder weather) offset by a decrease in the cost of gas sold (per Mcf) and the impact of regulatory adjustments. The increase in operating revenues was partially offset by a $1.0 million decrease in transportation revenues. The $1.0 million decrease in transportation revenues (despite higher volumes and colder weather) was primarily due to the migration of residential customers from transportation sales to retail sales combined with lower revenues from the cashout of gas imbalances with marketers.

Operating revenues for the Utility segment increased $48.8 million for the nine months ended June 30, 2018 as compared with the nine months ended June 30, 2017. The increase largely resulted from a $61.3 million increase in retail gas sales revenues and a $1.5 million increase in transportation revenues. The increase in retail gas sales revenues was largely a result of higher volumes (due to colder weather), an increase in the cost of gas sold (per Mcf) and the impact of new rates. The increase in transportation revenues was primarily due to a 5.9 Bcf increase in transportation throughput due to colder weather, partially offset by the impact of regulatory adjustments. These increases were partially offset by a $3.6 million decrease in off-system sales (due to lower volumes) and a $10.4 million decrease in other revenues. The $10.4 million decrease in other revenues was largely due to an $11.8 million estimated refund provision recorded during the nine months ended June 30, 2018 for the current income tax benefits resulting from the 2017 Tax Reform Act, partially offset by the impact of regulatory adjustments. 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, 2018 were $3.9 million, a decrease of $0.4 million when compared with earnings of $4.3 million for the quarter ended June 30, 2017. The decrease in earnings was largely attributable to higher operating expenses of $1.0 million (primarily due to higher pension costs) and the net impact of the 2017 Tax Reform Act, which lowered earnings by $0.3 million. These decreases were partially offset by the impact of colder weather in fiscal 2018 compared to fiscal 2017 ($0.7 million).

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, 2018, the WNC reduced earnings by approximately $0.8 million, as the weather was colder than normal. For the quarter ended June 30, 2017, the WNC increased earnings by approximately $0.5 million, as the weather was warmer than normal.

The Utility segment's earnings for the nine months ended June 30, 2018 were $58.3 million, an increase of $7.2 million when compared with earnings of $51.1 million for the quarter ended June 30, 2017. Higher earnings associated with the new rate order issued by the NYPSC effective April 1, 2017 ($2.8 million), the impact of colder weather in fiscal 2018 compared to fiscal 2017 ($5.6 million), lower interest expense ($0.8 million) and the current tax benefit associated with the 2017 Tax Reform Act, net of refund provision ($2.0 million) were partially offset by the impact of higher income tax expense of $2.2 million (largely due to higher state income taxes) and higher operating expenses ($0.5 million). The increase in operating expenses is primarily due to higher amortization of environmental remediation costs that resulted from the new rate order combined with higher personnel costs, partially offset by lower pension costs. The decrease in interest expense was largely due to lower intercompany long-term borrowing interest rates for the Utility segment.

For the nine months ended June 30, 2018, the WNC increased earnings by approximately $0.2 million, as the weather was warmer than normal. For the nine months ended June 30, 2017, the WNC increased earnings by approximately $4.3 million, as the weather was warmer than normal.

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Natural Gas (after Hedging)	$ 25,970	$ 25,017	$ 953	$ 120,289	$ 112,753	$ 7,536
Other	2	8	(6)	39	57	(18)
	$ 25,972	$ 25,025	$ 947	$ 120,328	$ 112,810	$ 7,518

Energy Marketing Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2018	2017	Increase (Decrease)	2018	2017	Increase (Decrease)
Natural Gas – (MMcf)	8,322	7,722	600	36,413	32,969	3,444

2018 Compared with 2017

Operating revenues for the Energy Marketing segment increased $0.9 million for the quarter ended June 30, 2018 as compared with the quarter ended June 30, 2017 . Operating revenues for the Energy Marketing segment increased $7.5 million for the nine months ended June 30, 2018 as compared with the nine months ended June 30, 2017 . The increases for the quarter and the nine month-period were primarily a result of an increase in gas sales revenue due to an increase in volume sold to retail customers as a result of colder weather and additional business from new customers, partially offset by a lower average price of natural gas period over period.

The Energy Marketing segment recorded a loss of $0.2 million for the quarter ended June 30, 2018, which was $0.4 million lower than the loss of $0.6 million recorded for the quarter ended June 30, 2017. The lower loss was primarily attributable to higher margin of $0.3 million. The increase in margin largely reflects a higher average margin per Mcf combined with the margin impact associated with the increase in volume sold to retail customers during the quarter ended June 30, 2018 as compared to the quarter ended June 30, 2017. The 2017 Tax Reform Act did not have a significant impact on Energy Marketing segment earnings for the quarter ended June 30, 2018.

The Energy Marketing segment earnings for the nine months ended June 30, 2018 were $1.4 million, a decrease of $0.7 million when compared with earnings of $2.1 million for the nine months ended June 30, 2017. This decrease in earnings was primarily attributable to lower margin of $0.9 million. The decrease in margin largely reflects a decline in average margin per Mcf primarily due to stronger natural gas prices at local purchase points relative to NYMEX-based sales contracts. The earnings decrease was slightly offset by lower operating expenses of $0.2 million, which primarily reflects lower pension costs and a decrease in advertising expenses. The 2017 Tax Reform Act did not have a significant impact on Energy Marketing segment earnings for the nine months ended June 30, 2018.

Corporate and All Other

2018 Compared with 2017

Corporate and All Other operations had a loss of $0.8 million for the quarter ended June 30, 2018, which was $0.5 million higher than the loss of $0.3 million for the quarter ended June 30, 2017. The increase in loss for the quarter is primarily attributed to higher income tax expense ($1.0 million), the impact of tax rate changes associated with the 2017 Tax Reform Act ($0.2 million), and higher depreciation expense ($0.3 million). These decreases in earnings were partially offset by higher margins of $0.6 million from the sale of standing timber by Seneca's land and timber division.

For the nine months ended June 30, 2018, Corporate and All Other operations had a loss of $17.9 million, which was $17.6 million higher than the loss of $0.3 million for the nine months ended June 30, 2017. The increase in loss for the nine months ended June 30, 2018 is primarily attributed to a remeasurement of accumulated deferred taxes under the 2017 Tax Reform Act ($17.8 million), higher income tax expense of $1.4 million (largely due to the impact of provision-to-return adjustments) and higher depreciation expense ($0.5 million). These decreases in earnings were partially offset by higher margins of $1.6 million from the sale of standing timber by Seneca's land and timber division.

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

Interest on long-term debt decreased $2.0 million for the quarter ended June 30, 2018 as compared with the quarter ended June 30, 2017 . For the nine months ended June 30, 2018, interest on long-term debt decreased $4.8 million as compared with the nine months ended June 30, 2017. These decreases are due to a decrease in the weighted average interest rate on long-term debt outstanding. The Company issued $300 million of 3.95% notes in September 2017 and repaid $300 million of 6.50% notes in October 2017.

CAPITAL RESOURCES AND LIQUIDITY

The Company’s primary sources of cash during the nine-month periods ended June 30, 2018 and June 30, 2017 consisted of cash provided by operating activities and net proceeds from the sale of oil and gas producing properties.

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, 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 $517.5 million for the nine months ended June 30, 2018, a decrease of $33.6 million compared with $551.1 million provided by operating activities for the nine months ended June 30, 2017. The decrease in cash provided by operating activities primarily reflects lower cash provided by operating activities in the Exploration and Production segment partially offset by an increase in cash provided by operating activities in the Utility segment. The decrease in the Exploration and Production segment was primarily due to lower cash receipts from crude oil and natural gas production as a result of lower natural gas prices and lower production. The increase in the Utility segment was primarily due to the timing of gas cost recovery.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets totaled $403.2 million during the nine months ended June 30, 2018 and $301.8 million during the nine months ended June 30, 2017 . The table below presents these expenditures:

Total Expenditures for Long-Lived Assets							
Nine Months Ended June 30, (Millions)		2018			2017			Increase (Decrease)
Exploration and Production:								
Capital Expenditures	$	269.9	(1)	$	168.5	(2)	$	101.4
Pipeline and Storage:								
Capital Expenditures		53.4	(1)		53.5	(2)		(0.1)
Gathering:								
Capital Expenditures		47.8	(1)		23.7	(2)		24.1
Utility:								
Capital Expenditures		52.0	(1)		56.4	(2)		(4.4)
All Other:								
Capital Expenditures		—			0.2			(0.2)
Eliminations		(19.9)			(0.5)			(19.4)
	$	403.2		$	301.8		$	101.4

(1) At June 30, 2018 , capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $49.0 million, $10.9 million, $8.2 million and $3.3 million, respectively, of non-cash capital expenditures. At September 30, 2017 , capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $36.5 million, $25.1 million, $3.9 million and $6.7 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, 2017 , capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $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.

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2018 were primarily well drilling and completion expenditures and included approximately $250.5 million for the Appalachian region (including $194.6 million in the Marcellus Shale area and $47.7 million in the Utica Shale area) and $19.4 million for the West Coast region. These amounts included approximately $132.8 million spent to develop proved undeveloped reserves.

The Company entered into a purchase and sale agreement to sell its oil and gas properties in the Sespe Field area of Ventura County, California in October 2017 for $43 million. The Company completed the sale on May 1, 2018, effective as of

October 1, 2017, receiving net proceeds of $38.2 million (included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statement of Cash Flows for the nine months ended June 30, 2018). The net proceeds received by the Company were adjusted for production revenue and production expenses retained by the Company between the effective date of the sale and the closing date, resulting in lower proceeds from sale at the closing date. The divestiture of the Company's oil and gas properties in the Sespe Field reflects continuing efforts to focus West Coast development activities in the San Joaquin basin, particularly at the Midway Sunset field in Kern County, California. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

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 jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. IOG holds an 80% working interest in all of the joint development wells. In total, IOG has funded $305.3 million as of June 30, 2018 for its 80% working interest in the 75 joint development wells, which includes $181.2 million of cash ($137.3 million in fiscal 2016, $26.6 million in fiscal 2017 and $17.3 million in the nine months ended June 30, 2018) included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statements of Cash Flows for fiscal 2016, fiscal 2017 and for the nine months ended June 30, 2018, respectively. Such proceeds from sale represent funding received from IOG for costs previously incurred by Seneca to develop a portion of the 75 joint development wells. 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, 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.

Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2018 were partially for additions, improvements and replacements to this segment's transmission and gas storage systems. In addition, the Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2018 include expenditures related to Supply Corporation's Line D Expansion Project ($14.3 million), as discussed below. The Pipeline and Storage 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) 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 have recently completed and are actively pursuing several expansion 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. Preliminary survey and investigation costs for expansion, routine replacement or modernization projects are initially recorded as Deferred Charges on the Consolidated Balance Sheet. Management may reserve for preliminary survey and investigation costs associated with large projects by reducing the Deferred Charges balance and increasing Operation and Maintenance Expense on the Consolidated Statement of Income. If it is determined that it is highly probable that a project for which a reserve has been established will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. 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.

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). 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. The Company also has pending with FERC a proceeding asserting, among other things, that the NYDEC exceeded the reasonable and statutory time frames to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. In light of these pending legal actions, the Company has not yet determined a target in-service date. The Company remains committed to the project. As of June 30, 2018, approximately $75.6 million has been spent on the Northern Access 2016 project, including $22.5 million that has been spent to study the project, for which no reserve has been established. The remaining $53.1 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 and services began November 1, 2017. The project included construction of a new 4,140 horsepower Keelor Compressor Station and modifications to the Bowen compressor station. The project also provides system modernization benefits. As of June 30, 2018, approximately $28.7 million has been spent on the Line D Expansion project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2018.

Empire concluded an Open Season on November 18, 2015, and has designed a project that would allow for the transportation of 205,000 Dth per day of additional shale supplies from interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline, and the TGP 200 Line (“Empire North Project”). This project is fully subscribed under long term agreements. Empire filed a Section 7(c) application with the FERC in February 2018. The Empire North Project has a projected in-service date in the second half of fiscal 2020 and an estimated capital cost of approximately $145 million. As of June 30, 2018 , approximately $3.0 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at June 30, 2018 .

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 pipeline extension of approximately 4.5 miles from Line N to the facility. Supply Corporation filed a prior notice application with FERC on March 23, 2018 and was authorized to pursue the project under its blanket certificate as of May 30, 2018. The proposed in-service date for this project is as early as June 1, 2019 at an estimated capital cost of approximately $20.2 million. As of June 30, 2018 , approximately $0.7 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at June 30, 2018 .

Supply Corporation is currently in the pre-filing process at FERC for its FM100 Project, which will upgrade 1950's era pipeline in northwestern Pennsylvania and create approximately 300,000 Dth per day of additional capacity on its system in Pennsylvania from a receipt point with NFG Midstream Clermont, LLC in McKean County to the Transcontinental Gas Pipe Line Company, LLC (“Transco”) system at Leidy, Pennsylvania. A precedent agreement has been executed by Supply Corporation and Transco whereby this additional capacity is expected to be leased by Transco, and will be part of the capacity Transco will offer in connection with a to-be-announced expansion project that will make available capacity from receipt points along its Leidy Line to Zone 6 markets. Seneca will be an anchor shipper on Transco’s project, providing Seneca with an outlet to premium markets for its Marcellus and Utica production from both the Clermont-Rich Valley and Trout Run-Gamble areas. The preliminary cost estimate for the entire project is approximately $280 million. As of June 30, 2018, approximately $1.1 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at June 30, 2018.

Gathering

The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2018 were for the purchase of two compressor stations for Midstream Company's Covington Gathering System, as well as the continued buildout of Midstream Company’s Trout Run Gathering System and Midstream Company's Clermont Gathering System, as discussed below. The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2017 were for the construction of the Clermont Gathering System.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Company, is building an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The total cost estimate for the continued buildout will be dependent on the nature and timing of Seneca's long-term plans. As of June 30, 2018 , approximately $292.3 million has been spent on the Clermont Gathering System, including approximately $11.0 million spent during the nine months ended June 30, 2018, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2018 .

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Company, 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 48 miles of backbone and in-field gathering pipelines, two compressor stations and a dehydration and metering station. As of June 30, 2018 , approximately $196.1 million has been spent on the Trout Run Gathering System, including approximately $18.7 million spent during the nine months ended June 30, 2018, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2018 .

NFG Midstream Wellsboro, LLC, a wholly owned subsidiary of Midstream Company, continues to develop its Wellsboro Gathering System in Tioga County, Pennsylvania. As of June 30, 2018, the Company has spent approximately $7.4 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, 2018.

Utility

The majority of the Utility segment capital expenditures for the nine months ended June 30, 2018 and June 30, 2017 were made for main and service line improvements and replacements, as well as main extensions.

Project Funding

Over the past two years, 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 as well as proceeds received from the sale of oil and gas assets. Going forward, while the Company expects to use cash on hand and cash from operations as the first means of financing these projects, the Company may issue short-term and/or long-term debt as necessary during fiscal 2018 to help meet its capital expenditures needs. The level of short-term and long-term borrowings will depend upon the amount of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells.

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, 2018 or September 30, 2017, nor was there any short-term debt outstanding during the nine months ended June 30, 2018. 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 what now numbers 13 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through December 5, 2019. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines.

The total amount available to be issued under the Company’s commercial paper program is $500.0 million. The commercial paper program is backed by the Credit Agreement, which provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter from October 1, 2017 through December 5, 2019. At June 30, 2018, the Company’s debt to capitalization ratio (as calculated under the facility) was .52. The constraints specified in the Credit Agreement would have permitted an additional $1.49 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company’s debt to capitalization ratio exceeded .65.

A downgrade in the Company’s credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company's subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets. However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources, including cash provided by operations.

The Credit Agreement contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of June 30, 2018 , the Company did not have any debt outstanding under the Credit Agreement.

The Current Portion of Long-Term Debt at June 30, 2018 consists of $250.0 million aggregate principal amount of 8.75% notes that mature in May 2019. The Current Portion of Long-Term Debt at September 30, 2017 consisted of $300.0 million aggregate principal amount of 6.50% notes that were scheduled to mature in April 2018. The Company redeemed the 6.50% notes on October 18, 2017 for $307.0 million, plus accrued interest.

The Company’s embedded cost of long-term debt was 5.16% and 5.52% at June 30, 2018 and June 30, 2017 , respectively.

Under the Company’s existing indenture covenants at June 30, 2018 , the Company would have been permitted to issue up to a maximum of $749.0 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 of 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 $99.0 million (or 4.7%) of the Company’s long-term debt (as of June 30, 2018) 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 $31.7 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, 2018 , the Company contributed $27.6 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $2.7 million to its VEBA trusts for its other post-retirement benefits. In the remainder of 2018 , the Company may contribute up to $5.0 million to the Retirement Plan and the Company expects to contribute approximately $0.2 million to its VEBA trusts.

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 that are designed to promote transparency, mitigate systemic risk and protect against market abuse. Although regulators have issued certain regulations, other rules that may impact the Company have yet to be finalized.

The CFTC's Dodd-Frank regulations continue to preserve the ability of non-financial end users to hedge their risks using swaps without being subject to mandatory clearing. In 2015, legislation was enacted to exempt from margin requirements swaps used by non-financial end-users to hedge or mitigate commercial risk. 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 the Company reduces its use of hedging transactions as a result of final regulations to be issued by the CFTC, results of operations may become more volatile and cash flows may be less predictable. There may be other rules developed by the CFTC and other regulators that could impact the Company. While many of those rules 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 final rules through higher transaction costs and prices or other direct or indirect costs.

Finally, given the additional authority granted to the CFTC on anti-market manipulation, anti-fraud and disruptive trading practices, it is difficult to predict how the evolving enforcement priorities of the CFTC will impact our business. Should the Company violate any laws or regulations applicable to our hedging activities, it could be subject to CFTC enforcement action and material penalties and sanctions. The Company continues to monitor these enforcement and other regulatory developments, but cannot predict the impact that evolving application of the Dodd-Frank Act may 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, 2018 , 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 2017 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

Distribution Corporation's current delivery rates in its New York jurisdiction were approved by the NYPSC in an order issued on April 20, 2017 with rates becoming effective May 1, 2017. On July 28, 2017, Distribution Corporation filed an appeal with New York State Supreme Court, Albany County, seeking review of the Order. The appeal contends that portions of the Order should be invalidated because they fail to meet the applicable legal standard for agency decisions. On December 11, 2017, the appeal was transferred to the Supreme Court, Appellate Division, Third Department. The Company cannot predict the outcome of the appeal at this time.

On December 29, 2017, the NYPSC issued an order instituting a proceeding to study the potential effects of the enactment of the 2017 Tax Reform Act on the tax expenses and liabilities of New York utilities. The order stated the NYPSC’s intent to ensure that the net benefits resulting from tax reform were preserved for ratepayers. Pursuant to the order, a technical conference was held with the utilities in February 2018, and the New York Department of Public Service Staff subsequently issued a proposal for accounting and ratemaking treatment of the tax changes. The NYPSC has not yet acted on this proposal. On June 4, 2018, Distribution Corporation filed a petition with the NYPSC regarding Distribution Corporation’s proposed disposition of net federal income tax savings resulting from the 2017 Tax Reform Act seeking authorization to 1) implement a customer refund program to return the net effect of the recent federal income tax rate reduction to Distribution Corporation’s customers and 2) allow Distribution Corporation recovery for the improvements to the Company’s imputed equity ratio directly resulting from the recent federal tax rate reduction. Distribution Corporation has requested the NYPSC to act on its petition in advance of the 2018-2019 winter heating season, but cannot predict the timing or outcome of its petition at this time. Refer to Item 1 at Note 4 - Income Taxes for further discussion of the 2017 Tax Reform Act.

Pennsylvania Jurisdiction

Distribution Corporation’s Pennsylvania jurisdiction delivery rates are being charged to customers in accordance with a rate settlement approved by the PaPUC. The rate settlement does not specify any requirement to file a future rate case.

By Secretarial Letter issued February 12, 2018, the PaPUC initiated a proceeding to determine the effects of the 2017 Tax Reform Act on the tax liabilities of PaPUC-regulated public utilities for 2018 and future years and the feasibility of reflecting such impacts on the rates charged to utility ratepayers. On March 15, 2018, the PaPUC issued a Temporary Rates Order making Distribution Corporation’s rates (along with the rates of other Pennsylvania public utilities not presently in a general rate increase proceeding) temporary for a period of six months. On May 17, 2018, the PaPUC issued an Order to Distribution Corporation, superceding and canceling Distribution Corporation’s temporary rates filed pursuant to the March 15, 2018 order and requiring that Distribution Corporation file a tariff supplement establishing temporary rates to implement refunds of 2.2% on customer rates beginning July 1, 2018. Distribution Corporation has filed the necessary tariff supplement to implement such refunds effective July 1, 2018. The May 17, 2018 PaPUC Order provides for a number of options regarding the permanent or temporary status of these rates and associated cost and rate deferral options. The Company is currently evaluating these specific options. Refer to Item 1 at Note 4 - Income Taxes for further discussion of the 2017 Tax Reform Act.

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.

Empire filed a Section 4 rate case on June 29, 2018, proposing rate increases to be effective August 1, 2018. The proposed rates reflect an annual cost of service of $71.5 million, a rate base of $246.8 million, and a proposed return on equity of 14%. The proposed rate increases are expected to be suspended, with an effective date of January 1, 2019, subject to refund. Lower storage rates are expected to be effective August 1, 2018. If the proposed rate increases finally approved at the end of the proceeding exceed the rates that were in effect at June 29, 2018, but are less than rates put into effect subject to refund on January 1, 2019, Empire would be required to refund the difference between the rates collected subject to refund and the final approved rates, with interest at the FERC-approved rate. If the rates approved at the end of the proceeding are lower than the rates in effect at June 29, 2018, such lower rates will become effective prospectively from the date of the applicable FERC order, and refunds with interest will be limited to the difference between the rates collected subject to refund and the rates in effect at June 29, 2018.

On July 18, 2018, the FERC issued a Final Rule in RM18-11-000, et. al, (Order No. 849) which requires pipelines to file a new form isolating the tax impact to each pipeline and also to make an election regarding the action the pipelines will take to address the lower tax rates, one of which is filing a Section 4 rate proceeding or Notice of Inquiry regarding treatment of accumulated deferred income taxes and other tax issues associated with the 2017 Tax Reform Act. Supply Corporation will be required to address the Order by December 6, 2018. At this point, the Company cannot predict the outcome of any action proposed pursuant to the Order. Refer to Note 4 - Income Taxes for further discussion of the 2017 Tax Reform Act.

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 review and potentially roll back many of these regulations, and, in turn, litigation (not involving the Company) 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. A number of states have adopted energy strategies or plans with goals that include the reduction of greenhouse gas emissions. For example, New York's State Energy Plan includes Reforming the Energy Vision (REV) initiatives which set greenhouse gas emission reduction targets of 40% by 2030 and 80% by 2050. Additionally, the Plan targets that 50% of electric generation must come from renewable energy sources by 2030. Similarly, Pennsylvania has a methane reduction framework for the oil and gas industry which will result in permitting changes with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines. 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 retrofit existing equipment, 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.

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," "believes," "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. 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;
5. Changes in the price of natural gas or oil;
6. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
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;
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. The impact of potential information technology, cybersecurity or data security breaches;
20. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war;
21. Significant differences between the Company's projected and actual capital expenditures and operating expenses; or
22. 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, 2018 .

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, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

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

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

Item 1A. Risk Factors

The risk factors in Item 1A of the Company's 2017 Form 10-K, as amended by Item 1A of Part II of the Company's Form 10-Q for the quarter ended December 31, 2017, have not materially changed.

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

On April 2, 2018, the Company issued a total of 6,888 unregistered shares of Company common stock to eight non-employee directors of the Company then serving on the Board of Directors of the Company, 861 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, 2018 . 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, 2018	—	N/A	—	6,971,019
May 1 - 31, 2018	1,221	$51.23	—	6,971,019
June 1 - 30, 2018	8,184	$52.70	—	6,971,019
Total	9,405	$52.51	—	6,971,019

(a) Represents (i) shares of common stock of the Company purchased on the open market with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock-based compensation awards for the payment of applicable withholding taxes. During the quarter ended June 30, 2018 , the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 9,405 shares purchased other than through a publicly announced share repurchase program, 6,650 were purchased for the Company's 401(k) plans and 2,755 were purchased as a result of shares tendered to the Company by holders of stock-based compensation awards.

(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 has not repurchased any shares since September 17, 2008 and has no plans to make further purchases in the near future.

Item 6. Exhibits

Exhibit Number	Description of Exhibit
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Nine Months Ended June 30, 2018 and the Fiscal Years Ended September 30, 2014 through 2017.
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, 2018 and 2017.
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, 2018 and 2017, (ii) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2018 and 2017, (iii) the Consolidated Balance Sheets at June 30, 2018 and September 30, 2017, (iv) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2018 and 2017 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.

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 3, 2018

EXHIBIT 12

NATIONAL FUEL GAS COMPANY
COMPUTATION OF RATIO OF
EARNINGS TO FIXED CHARGES
UNAUDITED

	For the Nine Months Ended	Fiscal Year Ended September 30,			
	June 30, 2018	2017	2016	2015	2014
(Dollars in Thousands)					
EARNINGS:					
Net Income (Loss) Available for Common Stock	$ 353,527	$ 283,482	$ (290,958)	$ (379,427)	$ 299,413
Plus Income Tax Expense (Benefit)	(23,825)	160,682	(232,549)	(319,136)	189,614
Less Investment Tax Credit (A)	(74)	(173)	(348)	(414)	(434)
Less Income from Unconsolidated Subsidiaries	—	—	—	—	(397)
Plus Distributions from Unconsolidated Subsidiaries	—	—	—	—	—
Plus Interest Expense on Long-Term Debt	82,412	116,471	117,347	95,916	90,194
Plus Other Interest Expense	2,742	3,366	3,697	3,555	4,083
Less Amortization of Loss on Reacquired Debt	(845)	(529)	(529)	(529)	(529)
Plus Allowance for Borrowed Funds Used in Construction	868	1,655	2,006	1,964	900
Plus Other Capitalized Interest	1,000	1,275	238	4,191	3,560
Plus Rentals (B)	5,386	4,615	9,479	13,866	13,700
	$ 421,191	$ 570,844	$ (391,617)	$ (580,014)	$ 600,104
FIXED CHARGES:					
Interest & Amortization of Premium and Discount of Funded Debt	$ 82,412	$ 116,471	$ 117,347	$ 95,916	$ 90,194
Plus Other Interest Expense	2,742	3,366	3,697	3,555	4,083
Less Amortization of Loss on Reacquired Debt	(845)	(529)	(529)	(529)	(529)
Plus Allowance for Borrowed Funds Used in Construction	868	1,655	2,006	1,964	900
Plus Other Capitalized Interest	1,000	1,275	238	4,191	3,560
Plus Rentals (B)	5,386	4,615	9,479	13,866	13,700
	$ 91,563	$ 126,853	$ 132,238	$ 118,963	$ 111,908
RATIO OF EARNINGS TO FIXED CHARGES	**4.60**	**4.50**	**(D)**	**(C)**	**5.36**

(A) Investment Tax Credit is included in Other Income.

(B) Rentals shown above represent the portion of all rentals (other than delay rentals) deemed representative of the interest factor.

(C) The ratio coverage for the fiscal year ended September 30, 2015 was less than 1:1. The Company would have needed to generate additional earnings of $698,977 to achieve a coverage of 1:1 for the fiscal year ended September 30, 2015.

(D) The ratio coverage for the fiscal year ended September 30, 2016 was less than 1:1. The Company would have needed to generate additional earnings of $523,855 to achieve a coverage of 1:1 for the fiscal year ended September 30, 2016.

EXHIBIT 31.1

CERTIFICATION

I, R. J. Tanski, certify that:

1. I have reviewed this quarterly report on Form 10-Q of National Fuel Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2018

/s/ R. J. Tanski
R. J. Tanski
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, D. P. Bauer, certify that:

1. I have reviewed this quarterly report on Form 10-Q of National Fuel Gas Company;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

(a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

(c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

(a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

(b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 3, 2018

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

EXHIBIT 32

NATIONAL FUEL GAS COMPANY

Certification Pursuant to Section 906
of the Sarbanes-Oxley Act of 2002

Each of the undersigned, R. J. TANSKI, President and Chief Executive Officer and D. P. BAUER, the Treasurer and Principal Financial Officer of NATIONAL FUEL GAS COMPANY (the "Company"), DOES HEREBY CERTIFY that:

1. The Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2018 (the "Report") fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934, as amended; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has executed this statement this 3rd day of August, 2018.

/s/ R. J. Tanski
President and Chief Executive Officer

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

Exhibit 99

NATIONAL FUEL GAS
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

(Thousands of Dollars)	Twelve Months Ended June 30, 2018	2017
INCOME		
Operating Revenues:		
Utility and Energy Marketing Revenues	$ 811,690	$ 746,650
Exploration and Production and Other Revenues	569,860	629,350
Pipeline and Storage and Gathering Revenues	208,860	209,416
	1,590,410	1,585,416
Operating Expenses:		
Purchased Gas	333,759	265,163
Operation and Maintenance:		
Utility and Energy Marketing	198,894	199,834
Exploration and Production and Other	149,215	138,388
Pipeline and Storage and Gathering	96,633	93,493
Property, Franchise and Other Taxes	84,872	84,159
Depreciation, Depletion and Amortization	233,185	224,929
Impairment of Oil and Gas Producing Properties	—	32,756
	1,096,558	1,038,722
Operating Income	493,852	546,694
Other Income (Expense):		
Interest Income	6,176	4,439
Other Income	5,807	7,375
Interest Expense on Long-Term Debt	(111,642)	(116,324)
Other Interest Expense	(3,428)	(2,439)
Income Before Income Taxes	390,765	439,745
Income Tax Expense (Benefit)	(8,338)	164,286
Net Income Available for Common Stock	**$ 399,103**	**$ 275,459**
Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$ 4.66	$ 3.23
Diluted:		
Net Income Available for Common Stock	$ 4.62	$ 3.21
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	85,719,552	85,239,850

Used in Diluted Calculation	86,333,307	85,881,424