NATIONAL FUEL GAS CO
Form 10-Q
February 01, 2019

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

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). YES þ NO ¨

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

Large Accelerated Filer þ	Accelerated Filer ¨
Non-Accelerated Filer ¨	Smaller Reporting Company ¨
	Emerging Growth Company ¨

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

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

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: Common stock, par value $1.00 per share, outstanding at January 31, 2019: 86,278,520 shares.

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GLOSSARY OF TERMS

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

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

Regulatory Agencies	
CFTC	Commodity Futures Trading Commission
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
NYDEC	New York State Department of Environmental Conservation
NYPSC	State of New York Public Service Commission
PaDEP	Pennsylvania Department of Environmental Protection
PaPUC	Pennsylvania Public Utility Commission
SEC	Securities and Exchange Commission
Other	
2018 Form 10-K	The Company’s Annual Report on Form 10-K for the year ended September 30, 2018
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.

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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.

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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.

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Part I. Financial Information

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

	Three Months Ended December 31,	
(Thousands of U.S. Dollars, Except Per Common Share Amounts)	2018	2017
INCOME		
Operating Revenues:		
Utility and Energy Marketing Revenues	$272,092	$225,725
Exploration and Production and Other Revenues	163,937	140,450
Pipeline and Storage and Gathering Revenues	54,218	53,480
	490,247	419,655
Operating Expenses:		
Purchased Gas	138,660	94,034
Operation and Maintenance:		
Utility and Energy Marketing	43,915	44,080
Exploration and Production and Other	32,795	35,083
Pipeline and Storage and Gathering	24,934	20,311
Property, Franchise and Other Taxes	24,005	20,848
Depreciation, Depletion and Amortization	64,255	55,830
	328,564	270,186
Operating Income	161,683	149,469
Other Income (Expense):		
Other Income (Deductions)	(9,602)	(3,503)
Interest Expense on Long-Term Debt	(25,439)	(28,087)
Other Interest Expense	(1,073)	(502)
Income Before Income Taxes	125,569	117,377
Income Tax Expense (Benefit)	22,909	(81,277)
Net Income Available for Common Stock	102,660	198,654
EARNINGS REINVESTED IN THE BUSINESS		
Balance at Beginning of Period	1,098,900	851,669
	1,201,560	1,050,323
Dividends on Common Stock	(36,663)	(35,590)
Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities	7,437	—
Balance at December 31	$1,172,334	$1,014,733
Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$1.19	$2.32

Diluted:		
Net Income Available for Common Stock	$1.18	$2.30
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	86,032,729	85,630,296
Used in Diluted Calculation	86,708,814	86,325,537
Dividends Per Common Share:		
Dividends Declared	$0.425	$0.415

See Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended December 31,	
(Thousands of U.S. Dollars)	2018	2017
Net Income Available for Common Stock	$102,660	$198,654
Other Comprehensive Income (Loss), Before Tax:		
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	—	(44)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	44,518	(5,499)
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	—	(430)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	20,517	(12,548)
Reclassification Adjustment for the Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities to Earnings Reinvested in the Business	(11,738)	—
Other Comprehensive Income (Loss), Before Tax	53,297	(18,521)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	—	(65)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	12,744	(2,305)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	—	(158)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	5,794	(5,197)
Reclassification Adjustment for Income Tax Benefit (Expense) on the Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities to Earnings Reinvested in the Business	(4,301)	—
Income Taxes – Net	14,237	(7,725)
Other Comprehensive Income (Loss)	39,060	(10,796)
Comprehensive Income	$141,720	$187,858

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	December 31, 2018	September 30, 2018
(Thousands of U.S. Dollars)		
ASSETS		
Property, Plant and Equipment	$ 10,604,089	$ 10,439,839
Less - Accumulated Depreciation, Depletion and Amortization	5,520,472	5,462,696
	5,083,617	4,977,143
Current Assets		
Cash and Temporary Cash Investments	109,754	229,606
Hedging Collateral Deposits	2,784	3,441
Receivables – Net of Allowance for Uncollectible Accounts of $26,318 and $24,537, Respectively	192,604	141,498
Unbilled Revenue	74,497	24,182
Gas Stored Underground	30,336	37,813
Materials and Supplies - at average cost	34,947	35,823
Unrecovered Purchased Gas Costs	8,700	4,204
Other Current Assets	69,219	68,024
	522,841	544,591
Other Assets		
Recoverable Future Taxes	114,219	115,460
Unamortized Debt Expense	15,412	15,975
Other Regulatory Assets	111,611	112,918
Deferred Charges	42,994	40,025
Other Investments	129,715	132,545
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	84,609	82,733
Fair Value of Derivative Financial Instruments	34,244	9,518
Other	42,190	102
	580,470	514,752
Total Assets	$ 6,186,928	$ 6,036,486

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of U.S. Dollars)	December 31, 2018	September 30, 2018
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 86,270,957 Shares and 85,956,814 Shares, Respectively	$ 86,271	$ 85,957
Paid in Capital	817,076	820,223
Earnings Reinvested in the Business	1,172,334	1,098,900
Accumulated Other Comprehensive Loss	(28,690)	(67,750)
Total Comprehensive Shareholders' Equity	2,046,991	1,937,330
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,131,880	2,131,365
Total Capitalization	4,178,871	4,068,695
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	—	—
Accounts Payable	127,926	160,031
Amounts Payable to Customers	—	3,394
Dividends Payable	36,663	36,532
Interest Payable on Long-Term Debt	30,016	19,062
Customer Advances	7,351	13,609
Customer Security Deposits	23,842	25,703
Other Accruals and Current Liabilities	191,172	132,693
Fair Value of Derivative Financial Instruments	2,112	49,036
	419,082	440,060
Deferred Credits		
Deferred Income Taxes	598,285	512,686
Taxes Refundable to Customers	366,448	370,628
Cost of Removal Regulatory Liability	214,842	212,311
Other Regulatory Liabilities	150,337	146,743
Pension and Other Post-Retirement Liabilities	40,842	66,103
Asset Retirement Obligations	104,343	108,235
Other Deferred Credits	113,878	111,025
	1,588,975	1,527,731
Commitments and Contingencies (Note 7)	—	—
Total Capitalization and Liabilities	$ 6,186,928	$ 6,036,486

See Notes to Condensed Consolidated Financial Statements

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

(Thousands of U.S. Dollars)	Three Months Ended December 31, 2018	2017
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$102,660	$198,654
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	64,255	55,830
Deferred Income Taxes	64,175	(94,676)
Stock-Based Compensation	5,311	3,905
Other	2,182	3,678
Change in:		
Receivables and Unbilled Revenue	(101,541)	(83,357)
Gas Stored Underground and Materials and Supplies	8,353	10,337
Unrecovered Purchased Gas Costs	(4,496)	(3,164)
Other Current Assets	(1,195)	3,591
Accounts Payable	1,502	13,173
Amounts Payable to Customers	(3,394)	251
Customer Advances	(6,258)	2,697
Customer Security Deposits	(1,861)	2,131
Other Accruals and Current Liabilities	38,412	11,532
Other Assets	(42,400)	(5,275)
Other Liabilities	(21,333)	(21,775)
Net Cash Provided by Operating Activities	104,372	97,532
INVESTING ACTIVITIES		
Capital Expenditures	(177,567)	(142,613)
Other	(2,549)	2,612
Net Cash Used in Investing Activities	(180,116)	(140,001)
FINANCING ACTIVITIES		
Reduction of Long-Term Debt	—	(307,047)
Dividends Paid on Common Stock	(36,532)	(35,500)
Net Repurchases of Common Stock	(8,233)	(1,501)
Net Cash Used in Financing Activities	(44,765)	(344,048)
Net Decrease in Cash, Cash Equivalents, and Restricted Cash	(120,509)	(386,517)
Cash, Cash Equivalents, and Restricted Cash at October 1	233,047	557,271
Cash, Cash Equivalents, and Restricted Cash at December 31	$112,538	$170,754
Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$86,175	$56,116
Receivable from Sale of Oil and Gas Producing Properties	$—	$17,310

See Notes to Condensed Consolidated Financial Statements

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

Note 1 - Summary of Significant Accounting Policies

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

Reclassifications. In November 2016, the FASB issued authoritative guidance related to the presentation of restricted cash on the statement of cash flows. The new guidance requires restricted cash and cash equivalents be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the statement of cash flows, and requires disclosure of how cash and cash equivalents on the statement of cash flows reconciles to the balance sheet. The Company considers Hedging Collateral Deposits to be restricted cash. The Company adopted this guidance effective October 1, 2018 on a retrospective basis. As a result, prior periods have been reclassified to conform to the current year presentation. Additional discussion is provided below at Consolidated Statement of Cash Flows.

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 Company adopted this guidance effective October 1, 2018. The Company applied the guidance retrospectively for the pension and postretirement benefit costs using amounts disclosed in prior period financial statement notes as estimates for the reclassifications in accordance with a practical expedient allowed under the guidance. Operating Income increased $7.5 million and Other Income (Deductions) decreased by the same amount for the quarter ended December 31, 2017 as a result of the reclassifications. For the quarter ended December 31, 2018, Other Income (Deductions) includes $7.4 million of pension and postretirement benefit costs.

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, 2018, 2017 and 2016 that are included in the Company's 2018 Form 10-K. The consolidated financial statements for the year ended September 30, 2019 will be audited by the Company's independent registered public accounting firm after the end of the fiscal year.

The earnings for the three months ended December 31, 2018 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2019. 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 8 – Business Segment Information.

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Consolidated Statements of Cash Flows. The components, as reported on the Company's Consolidated Balance Sheets, of the total cash, cash equivalents, and restricted cash presented on the Statement of Cash Flows are as follows (in thousands):

	Three Months Ended December 31, 2018		Three Months Ended December 31, 2017	
	Balance at October 1, 2018	Balance at December 31, 2018	Balance at October 1, 2017	Balance at December 31, 2017
Cash and Temporary Cash Investments	$229,606	$109,754	$555,530	$166,289
Hedging Collateral Deposits	3,441	2,784	1,741	4,465
Cash, Cash Equivalents, and Restricted Cash	$233,047	$112,538	$557,271	$170,754

The Company considers all highly liquid debt instruments purchased with a maturity date of generally three months or less to be cash equivalents. The Company's restricted cash is comprised entirely of amounts reported as Hedging Collateral Deposits on the Consolidated Balance Sheets. Hedging Collateral Deposits 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 $2.0 million at December 31, 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 $58.5 million and $62.2 million at December 31, 2018 and September 30, 2018, 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 December 31, 2018, the ceiling exceeded the book value of the oil and gas properties by approximately $776.3 million. In adjusting estimated future cash flows for hedging under the ceiling test at December 31, 2018, estimated future net cash flows were decreased by $44.4 million.

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Accumulated Other Comprehensive Loss. The components of Accumulated Other Comprehensive Loss and changes for the three months ended December 31, 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 December 31, 2018				
Balance at October 1, 2018	$ (28,611)	$ 7,437	$ (46,576)	$ (67,750)
Other Comprehensive Gains and Losses Before Reclassifications	31,774	—	—	31,774
Amounts Reclassified From Other Comprehensive Income (Loss)	14,723	(7,437)	—	7,286
Balance at December 31, 2018	$ 17,886	$ —	$ (46,576)	$ (28,690)
Three Months Ended December 31, 2017				
Balance at October 1, 2017	$ 20,801	$ 7,562	$ (58,486)	$ (30,123)
Other Comprehensive Gains and Losses Before Reclassifications	(3,194)	21	—	(3,173)
Amounts Reclassified From Other Comprehensive Income (Loss)	(7,351)	(272)	—	(7,623)
Balance at December 31, 2017	$ 10,256	$ 7,311	$ (58,486)	$ (40,919)

In January 2016, the FASB issued authoritative guidance regarding the recognition and measurement of financial assets and liabilities. The authoritative guidance primarily affects the accounting for equity investments and the presentation and disclosure requirements for financial instruments. All equity investments in unconsolidated entities will be measured at fair value through earnings rather than through accumulated other comprehensive income. The Company adopted this authoritative guidance effective October 1, 2018 and, as called for by the modified retrospective method of adoption, recorded a cumulative effect adjustment for the quarter ended December 31, 2018 to increase retained earnings by $7.4 million and decrease accumulated other comprehensive income by the same amount.

Reclassifications Out of Accumulated Other Comprehensive Loss. The details about the reclassification adjustments out of accumulated other comprehensive loss for the three months ended December 31, 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 December 31, 2018	2017	Affected Line Item in the Statement Where Net Income is Presented
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	($18,522)	$12,842	Operating Revenues
Commodity Contracts	(902)	196	Purchased Gas
Foreign Currency Contracts	(1,093)	(490)	Operating Revenues

Gains (Losses) on Securities Available for Sale	11,738	—	Earnings Reinvested in the Business
Gains (Losses) on Securities Available for Sale	—	430	Other Income (Deductions)
	(8,779)	12,978	Total Before Income Tax
	1,493	(5,355)	Income Tax Expense
	($7,286)	$7,623	Net of Tax

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

	At December 31, 2018	At September 30, 2018
Prepayments	$ 8,765	$ 11,126
Prepaid Property and Other Taxes	15,602	14,088
Federal Income Taxes Receivable	22,474	22,457
State Income Taxes Receivable	9,030	8,822
Fair Values of Firm Commitments	986	1,739
Regulatory Assets	12,362	9,792
	$ 69,219	$ 68,024

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

	At December 31, 2018	At September 30, 2018
Federal Income Taxes Receivable	$ 42,093	$ —
Other	97	102
	$ 42,190	$ 102

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

	At December 31, 2018	At September 30, 2018
Accrued Capital Expenditures	$ 69,321	$ 38,354
Regulatory Liabilities	45,343	57,425
Reserve for Gas Replacement	2,025	—
Liability for Royalty and Working Interests	26,801	12,062
Other	47,682	24,852
	$ 191,172	$ 132,693

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 SARs, restricted stock units and performance shares. For the quarter ended December 31, 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. SARs, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 318,106 securities and 157,603 securities excluded as being antidilutive for the quarters ended December 31, 2018 and December 31, 2017, respectively.

Stock-Based Compensation. The Company granted 244,734 performance shares during the quarter ended December 31, 2018. The weighted average fair value of such performance shares was $55.67 per share for the quarter ended December 31, 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 quarter ended December 31, 2018 must meet a performance goal related to relative return on capital over a three-year performance cycle. The performance goal over the performance cycle is the Company’s total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee (“Report Group”). Total return on capital for a given company means the average of the Report Group companies’ returns on capital for each twelve month period corresponding to each of the Company’s fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these performance shares that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value of these performance shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award. The other half of the performance shares granted during the quarter ended December 31, 2018 must meet a performance goal related to relative total shareholder return over a three-year performance cycle. 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 total 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 111,108 non-performance based restricted stock units during the quarter ended December 31, 2018. The weighted average fair value of such non-performance based restricted stock units was $49.72 per share for the quarter ended December 31, 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 February 2016, the FASB issued authoritative guidance, which has subsequently been amended, 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. The Company is currently reviewing all existing leases and other agreements that may be considered leases under the new authoritative guidance and evaluating the effect the revised guidance will have on its financial statements, internal controls, and related disclosures. The Company will continue to monitor relevant industry and regulatory guidance and adjust its implementation approach as necessary.

In August 2017, the FASB issued authoritative guidance which changes the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities and to simplify the application of hedge accounting. The new guidance will be effective as of the Company's first quarter of fiscal 2020, with early adoption permitted. The Company does not expect adoption of this guidance to have a significant impact on its consolidated financial statements and is currently evaluating the impact of this guidance.

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 will be filing with the FERC for regulatory approval of the reclassification to retained earnings for the Company’s Pipeline and Storage segment.

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Note 2 – Revenue from Contracts with Customers

The Company adopted authoritative guidance regarding revenue recognition on October 1, 2018 using the modified retrospective method of adoption for open contracts as of October 1, 2018. A cumulative effect adjustment to retained earnings was not necessary since no revenue recognition differences were identified when comparing the revenue recognition criteria under the new authoritative guidance to the previous guidance. The Company records revenue related to its derivative financial instruments in the Exploration and Production segment as well as in the Energy Marketing segment. The Company also records revenue related to alternative revenue programs in its Utility segment. Revenue related to derivative financial instruments and alternative revenue programs are excluded from the scope of the new authoritative guidance since they are accounted for under other existing accounting guidance.

The following table provides a disaggregation of the Company's revenues for the quarter ended December 31, 2018, presented by type of service from each reportable segment.

Quarter Ended December 31, 2018 (Thousands)

Revenues By Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Production of Natural Gas	$ 135,911	$—	$ —	$—	$ —	$—	$ —	$ 135,911
Production of Crude Oil	37,555	—	—	—	—	—	—	37,555
Natural Gas Processing	975	—	—	—	—	—	—	975
Natural Gas Gathering Services	—	—	29,690	—	—	—	(29,690)	—
Natural Gas Transportation Service	—	56,135	—	35,631	—	—	(17,065)	74,701
Natural Gas Storage Service	—	18,929	—	—	—	—	(7,973)	10,956
Natural Gas Residential Sales	—	—	—	166,867	—	—	—	166,867
Natural Gas Commercial Sales	—	—	—	22,047	—	—	—	22,047
Natural Gas Industrial Sales	—	—	—	1,501	—	—	—	1,501
Natural Gas Marketing	—	—	—	—	49,287	—	(332)	48,955
Other	382	2,005	—	(2,861)	—	1,007	(404)	129
Total Revenues from Contracts with Customers	174,823	77,069	29,690	223,185	49,287	1,007	(55,464)	499,597
Alternative Revenue Programs	—	—	—	(528)	—	—	—	(528)
Derivative Financial Instruments	(11,947)	—	—	—	3,125	—	—	(8,822)
Total Revenues	$ 162,876	$77,069	$ 29,690	$222,657	$ 52,412	$1,007	$ (55,464)	$ 490,247

Exploration and Production Segment Revenue

The Company’s Exploration and Production Segment records revenue from the sale of the natural gas and oil that it produces and natural gas liquids (NGLs) processed based on entitlement, which means that revenue is recorded based on the actual amount of natural gas or oil that is delivered to a pipeline, or upon pick-up in the case of NGLs, and the Company’s ownership interest. Natural gas production occurs primarily in the Appalachian region of the United States and crude oil production occurs primarily in the West Coast region of the United States. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance. The sales contracts generally require the Company to deliver a specific quantity of a commodity per day for a specific number of days at a price that is either fixed or variable and considers the delivery of each unit (MMBtu or Bbl) to be a separate performance obligation that is satisfied upon delivery.

The transaction price for the sale of natural gas, oil and NGLs is contractually agreed upon based on prevailing market pricing (primarily tied to a market index with certain adjustments based on factors such as delivery location and prevailing supply and demand conditions) or fixed pricing. The Company allocates the transaction price to each performance obligation on the basis of the relative standalone selling price of each distinct unit sold. Revenue is recognized at a point in time when the transfer of the commodity occurs at the delivery point per the contract. The amount billable, as determined by the contracted quantity and price, indicates the value to the customer, and is used for revenue recognition purposes by the Exploration and Production segment as specified by the “invoice practical expedient” (the amount that the Exploration and Production segment has the right to invoice) under the authoritative guidance for revenue recognition. The contracts typically require payment within 30 days of the end of the calendar month in which the natural gas and oil is delivered, or picked up in the case of NGLs.

The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment related to sales of the natural gas and oil that it produces. Gains or losses on such derivative financial instruments are recorded as adjustments to revenue; however, they are not considered to be revenue from contracts with customers.

Pipeline and Storage Segment Revenue

The Company's Pipeline and Storage segment records revenue for natural gas transportation and storage services in New York and Pennsylvania at tariff-based rates regulated by the FERC. Customers secure their own gas supply and the Pipeline and Storage segment provides transportation and/or storage services to move the customer-supplied gas to the intended location, including injections into or withdrawals from the storage field. This performance obligation is satisfied over time. The rate design for the Pipeline and Storage segment's customers generally includes a combination of volumetric or commodity charges as well as monthly "fixed" charges (including charges commonly referred to as capacity charges, demand charges, or reservation charges). These types of fixed charges represent compensation for standing ready over the period of the month to deliver quantities of gas, regardless of whether the customer takes delivery of any quantity of gas. The performance obligation under these circumstances is satisfied based on the passage of time and meter reads, if applicable, which correlates to the period for which the charges are eligible to be invoiced. The amount billable, as determined by the meter read and the "fixed" monthly charge, indicates the value to the customer, and is used for revenue recognition purposes by the Pipeline and Storage segment as specified by the "invoice practical expedient" (the amount that the Pipeline and Storage segment has the right to invoice) under the authoritative guidance for revenue recognition. Customers are billed after the end of each calendar month, with payment typically due by the 25th day of the month in which the invoice is received.

The Company's Pipeline and Storage segment expects to recognize the following revenue amounts in future periods related to "fixed" charges associated with remaining performance obligations for transportation and storage contracts: $123.5 million for the remainder of fiscal 2019; $149.4 million for fiscal 2020; $128.5 million for fiscal 2021; $113.6 million for fiscal 2022; $82.7 million for fiscal 2023; and $370.7 million thereafter.

Gathering Segment Revenue

The Company's Gathering segment provides gathering and processing services in the Appalachian region of Pennsylvania, primarily for Seneca. The Gathering segment's primary performance obligation is to deliver gathered natural gas volumes from Seneca's wells into interstate pipelines at contractually agreed upon per unit rates. This obligation is satisfied over time. The performance obligation is satisfied based on the passage of time and meter reads, which correlates to the period for which the charges are eligible to be invoiced. The amount billable, as determined by the meter read and the contracted volumetric rate, indicates the value to the customer, and is used for revenue recognition purposes by the Gathering segment as specified by the "invoice practical expedient" (the amount that the Gathering segment has the right to invoice) under the authoritative guidance for revenue recognition. Customers are billed after the end of each calendar month, with payment typically due by the 10th day after the invoice is received.

Utility Segment Revenue

The Company's Utility segment records revenue for natural gas sales and natural gas transportation services in western New York and northwestern Pennsylvania at tariff-based rates regulated by the NYPSC and the PaPUC. Natural gas sales and transportation services are provided largely to residential, commercial and industrial customers. The Utility segment's performance obligation to its customers is to deliver natural gas, an obligation which is satisfied over time. This obligation generally remains in effect as long as the customer consumes the natural gas provided by the Utility segment. The Utility segment recognizes revenue when it satisfies its performance obligation by delivering natural gas to the customer. Natural gas is delivered and consumed by the customer simultaneously. The satisfaction of the performance obligation is measured by the turn of the meter dial. The amount billable, as determined by the meter read and the tariff-based rate, indicates the value to the customer, and is used for revenue recognition purposes by the Utility segment as specified by the "invoice practical expedient" (the amount that the Utility segment has the right to invoice) under the authoritative guidance for revenue recognition. Since the Utility segment bills its customers in cycles having billing dates that do not generally coincide with the end of a calendar month, a receivable is recorded for natural gas delivered but not yet billed to customers based on an estimate of the amount of natural gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets. The Utility segment's tariffs allow customers to utilize budget billing. In this situation, since the amount billed may differ from the amount of natural gas delivered to the customer in any given month, revenue is recognized monthly based on the amount of natural gas consumed. The differential between the amount billed and the amount consumed is recorded as a component of Receivables or Customer Advances on the Consolidated Balance Sheets. All receivables or advances related to budget billing are settled within one year.

Utility Segment Alternative Revenue Programs

As indicated in the revenue table shown above, the Company's Utility segment has alternative revenue programs that are excluded from the scope of the new authoritative guidance regarding revenue recognition. The NYPSC has authorized alternative revenue programs that are designed to mitigate the impact that weather and conservation have on margin. The NYPSC has also authorized additional alternative revenue programs that adjust billings for the effects of broad external factors or to compensate the Company for demand-side management initiatives. These alternative revenue programs primarily allow the Company and customer to share in variances from imputed margins due to migration of transportation customers, allow for adjustments to the gas cost recovery mechanism for fluctuations in uncollectible expenses associated with gas costs, and allow the Company to pass on to customers costs associated with customer energy efficiency programs. In general, revenue is adjusted monthly for these programs and is collected from or passed back to customers within 24 months of the annual reconciliation period.

Energy Marketing Segment Revenue

The Company's Energy Marketing segment records revenue for competitively priced natural gas sales in western and central New York and northwestern Pennsylvania. Sales are provided largely to industrial, wholesale, commercial, public authority and residential customers. The Energy Marketing segment's performance obligation to its customers is to deliver natural gas, an obligation which is satisfied over time. This obligation generally remains in effect as long as the customer consumes the natural gas provided by the Energy Marketing segment. The Energy Marketing segment recognizes revenue when it satisfies its performance obligation by delivering natural gas to the customer. Natural gas is delivered and consumed by the customer simultaneously. The satisfaction of the performance obligation is measured by the turn of the meter dial. The amount billable, as determined by the meter read and the contracted or market based rate, indicates the value to the customer, and is used for revenue recognition purposes by the Energy Marketing segment as specified by the "invoice practical expedient" (the amount that the Energy Marketing segment has the right to invoice) under the authoritative guidance for revenue recognition. Since the Energy Marketing segment bills its residential customers in cycles having billing dates that do not generally coincide with the end of a calendar month, a receivable is recorded for natural gas delivered but not yet billed to customers based on an estimate of the amount of natural gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets. The Energy Marketing segment also allows customers to utilize budget billing. In this situation, since the amount billed may differ from the amount of natural gas delivered to the customer in any given month, revenue is recognized monthly based on the amount of natural gas consumed. The differential between the amount billed and the amount consumed is recorded as a component of Receivables or Customer Advances on the Consolidated Balance Sheets. All receivables or advances related to budget billing are settled within one year.

The Company uses derivative financial instruments to manage commodity price risk in the Energy Marketing segment related to the sale of natural gas to its customers. Gains or losses on such derivative financial instruments are recorded as adjustments to revenue; however, they are not considered to be revenue from contracts with customers.

Note 3 – Fair Value Measurements

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

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The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of December 31, 2018 and September 30, 2018. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over the counter swaps combines gas and oil swaps because a significant number of the counterparties enter into both gas and oil swap agreements with the Company.

Recurring Fair Value Measures	At fair value as of December 31, 2018				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[(1)]	Total[(1)]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$86,168	$—	$ —	$ —	$86,168
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	1,077	—	—	(1,077)	—
Over the Counter Swaps – Gas and Oil	—	43,274	—	(5,393)	37,881
Foreign Currency Contracts	—	—	—	(3,637)	(3,637)
Other Investments:					
Balanced Equity Mutual Fund	35,498	—	—	—	35,498
Fixed Income Mutual Fund	53,367	—	—	—	53,367
Common Stock – Financial Services Industry	1,437	—	—	—	1,437
Hedging Collateral Deposits	2,784	—	—	—	2,784
Total	$180,331	$43,274	$ —	$ (10,107)	$213,498
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$2,291	$—	$ —	$ (1,077)	$1,214
Over the Counter Swaps – Gas and Oil	—	6,249	—	(5,393)	856
Foreign Currency Contracts	—	3,679	—	(3,637)	42
Total	$2,291	$9,928	$ —	$ (10,107)	$2,112
Total Net Assets/(Liabilities)	$178,040	$33,346	$ —	$ —	$211,386

Recurring Fair Value Measures	At fair value as of September 30, 2018				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[(1)]	Total[(1)]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$215,272	$—	$ —	$ —	$215,272
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	1,075	—	—	(1,075)	—
Over the Counter Swaps – Gas and Oil	—	26,074	—	(17,041)	9,033
Foreign Currency Contracts	—	443	—	(443)	—
Other Investments:					
Balanced Equity Mutual Fund	38,468	—	—	—	38,468
Fixed Income Mutual Fund	51,331	—	—	—	51,331
Common Stock – Financial Services Industry	2,776	—	—	—	2,776
Hedging Collateral Deposits	3,441	—	—	—	3,441
Total	$312,363	$26,517	$ —	$ (18,559)	$320,321
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$2,412	$—	$ —	$ (1,075)	$1,337

Over the Counter Swaps – Gas and Oil	—	64,224	—	(17,041)	47,183
Foreign Currency Contracts	—	959	—	(443)	516
Total	$2,412	$65,183	$ —	$ (18,559)	$49,036
Total Net Assets/(Liabilities)	$309,951	$(38,666)	$ —	$ —	$271,285

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

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Derivative Financial Instruments

At December 31, 2018 and September 30, 2018, 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 $2.8 million at December 31, 2018 and $3.4 million at September 30, 2018, which were associated with these futures contracts and have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at December 31, 2018 and September 30, 2018 consist of natural gas price swap agreements used in the Company’s Exploration and Production and Energy Marketing segments, crude oil price swap agreements used in the Company’s Exploration and Production segment and foreign currency contracts used in the Company's Exploration and Production segment. The derivative financial instruments reported in Level 2 at December 31, 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 December 31, 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 ended December 31, 2018 and December 31, 2017, there were no assets or liabilities measured at fair value and classified as Level 3. For the quarters ended December 31, 2018 and December 31, 2017, no transfers in or out of Level 1 or Level 2 occurred.

Note 4 – Financial Instruments

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

	December 31, 2018		September 30, 2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$2,131,880	$2,114,990	$2,131,365	$2,121,861

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

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

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

	At December 31, 2018	At September 30, 2018
Life Insurance Contracts	$ 39,413	$ 39,970
Equity Mutual Fund	35,498	38,468
Fixed Income Mutual Fund	53,367	51,331
Marketable Equity Securities	1,437	2,776
	$ 129,715	$ 132,545

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 with changes in fair value recognized in net income. 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 7 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 December 31, 2018 and September 30, 2018. 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 December 31, 2018, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	97.3	Bcf (short positions)

Natural Gas	2.4	Bcf (long positions)
Crude Oil	3,735,000	Bbls (short positions)

As of December 31, 2018, the Company was hedging a total of $89.5 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts (long positions).
As of December 31, 2018, the Company had $27.6 million ($17.9 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $15.2 million ($9.9 million after tax) of unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transactions are recorded in earnings.

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended December 31, 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 December 31,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Three Months Ended December 31,		Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Three Months Ended December 31,	
	2018	2017		2018	2017		2018	2017
Commodity Contracts	$50,052	$(5,948)	Operating Revenue	$(18,522)	$12,842	Operating Revenue	$6,505	$(433)
Commodity Contracts	(1,279)	956	Purchased Gas	(902)	196	Not Applicable	—	—
Foreign Currency Contracts	(4,255)	(507)	Operating Revenue	(1,093)	(490)	Not Applicable	—	—
Total	$44,518	$(5,499)		$(20,517)	$12,548		$6,505	$(433)

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 December 31, 2018, the Company’s Energy Marketing segment had fair value hedges covering approximately 25.6 Bcf (25.4 Bcf of fixed price sales commitments and 0.2 Bcf of commitments related to the withdrawal of storage gas). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

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

		Derivative Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2018 (In Thousands)	the Hedged Item Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2018 (In Thousands)
Commodity Contracts	Operating Revenues	$ (78)	$ 78
Commodity Contracts	Purchased Gas	$ 142	$ (142)
		$ 64	$ (64)

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 fourteen are in a net gain position. On average, the Company had $2.4 million of credit exposure per counterparty in a gain position at December 31, 2018. The maximum credit exposure per counterparty in a gain position at December 31, 2018 was $6.6 million. As of December 31, 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 December 31, 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 December 31, 2018, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $21.1 million according to the Company’s internal model (discussed in Note 3 — Fair Value Measurements). At December 31, 2018, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $0.9 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 December 31, 2018.

For its exchange traded futures contracts, the Company was required to post $2.8 million in hedging collateral deposits as of December 31, 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.

Note 5 - Income Taxes

The effective tax rate for the quarters ended December 31, 2018 and December 31, 2017 was 18.2% and negative 69.2%, respectively. The difference primarily relates to the impact of the one-time remeasurement of accumulated deferred income taxes under the 2017 Tax Reform Act during fiscal 2018 discussed below.
On December 22, 2017, 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. In addition, beginning in fiscal 2019, the corporate alternative minimum tax (AMT) is eliminated and there are enhanced limitations on the deductibility of certain executive compensation. For the rate regulated subsidiaries, the 2017 Tax Reform Act also allows for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after

September 30, 2018 and the continuation of certain rate normalization requirements for accelerated depreciation benefits. The non-rate regulated subsidiaries are allowed full expensing of certain property acquired after September 27, 2017 and have potential limitations on the deductibility of interest expense beginning in fiscal 2019.

The changes noted above had a material impact on the financial statements in the year ended September 30, 2018. The Company’s accumulated deferred income taxes were remeasured based upon the new tax rates. For the non-rate regulated activities through the year ended September 30, 2018, the change in beginning of the year deferred income taxes of $103.5 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. For further discussion, refer to Note 10 - Regulatory Matters.

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The 2017 Tax Reform Act also provides that the Company's existing AMT credit carryovers are refundable, if not utilized to reduce tax, beginning in fiscal 2019. During fiscal 2018, the Department of Treasury indicated that a portion of the refundable AMT credit carryovers would be subject to sequestration. Accordingly, the Company recorded a \$5.0 million valuation allowance related to this sequestration. During the quarter ended December 31, 2018, the Office of Management and Budget determined that these AMT refunds would not be subject to sequestration. As such, the Company has removed the valuation allowance. In addition, the Company reclassified the estimated fiscal 2019 refund, approximately \$42.1 million, from Deferred Income Taxes to Other Assets.
The SEC issued guidance in Staff Accounting Bulletin 118 (SAB 118) which provided 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. Based upon the available guidance, the Company has completed the remeasurement of accumulated deferred income taxes. Any subsequent guidance or clarification related to the 2017 Tax Reform Act will be accounted for in the period issued.

Note 6 - Capitalization

Summary of Changes in Common Stock Equity

	Common Stock			Earnings	Accumulated
			Paid In	Reinvested	Other
	Shares	Amount	Capital	in the Business	Comprehensive Income (Loss)
	(Thousands, except per share amounts)				
Balance at October 1, 2017	85,543	\$85,543	\$796,646	\$851,669	\$ (30,123)
Net Income Available for Common Stock				198,654	
Dividends Declared on Common Stock (\$0.415 Per Share)				(35,590)	
Other Comprehensive Loss, Net of Tax					(10,796)
Share-Based Payment Expense [1]			3,511		
Common Stock Issued Under Stock and Benefit Plans	218	218	191		
Balance at December 31, 2017	85,761	85,761	800,348	1,014,733	(40,919)
Balance at October 1, 2018	85,957	\$85,957	\$820,223	\$1,098,900	\$ (67,750)
Net Income Available for Common Stock				102,660	
Dividends Declared on Common Stock (\$0.425 Per Share)				(36,663)	
Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities				7,437	
Other Comprehensive Income, Net of Tax					39,060
Share-Based Payment Expense [1]			4,917		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	314	314	(8,064)		
Balance at December 31, 2018	86,271	\$86,271	\$817,076	\$1,172,334	\$ (28,690)

(1) Paid in Capital includes compensation costs associated with performance shares and/or restricted stock awards. The expense is included within Net Income Available For Common Stock, net of tax benefits.

Common Stock. During the three months ended December 31, 2018, the Company issued 94,047 original issue shares of common stock as a result of SARs exercises, 79,654 original issue shares of common stock for restricted stock units that vested and 281,882 original issue shares of common stock for performance shares that vested. The Company also issued 7,020 original issue shares of common stock to the non-employee directors of the Company who receive compensation under the Company's 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors' services during the three months ended December 31, 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 three months ended December 31, 2018, 148,460 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

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Current Portion of Long-Term Debt. None of the Company's long-term debt as of December 31, 2018 and September 30, 2018 had a maturity date within the following twelve-month period.

Note 7 - Commitments and Contingencies

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

At December 31, 2018, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately $7.5 million, which includes a $4.1 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 December 31, 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 Project. On February 3, 2017, Supply Corporation and Empire received FERC approval of the Northern Access 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. On August 6, 2018, the FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. Rehearing requests have been filed at FERC. In light of these pending legal actions and the need to complete necessary project development activities in advance of construction, the target in-service date for the project is expected to be no earlier than fiscal 2022. As a result of the decision of the NYDEC, Supply Corporation and Empire evaluated the capitalized project costs for impairment as of December 31, 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 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 $76.5 million at December 31, 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 8 – 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 2018 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 2018 Form 10-K. A listing of segment assets at December 31, 2018 and September 30, 2018 is shown in the tables below.

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Quarter Ended December 31, 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	$162,876	$54,218	$—	$220,012	$52,080	$489,186	$1,007	$54	$490,247
Intersegment Revenues	$—	$22,851	$29,690	$2,645	$332	$55,518	$—	$(55,518)	$—
Segment Profit: Net Income (Loss)	$38,214	$25,102	$14,183	$25,649	$(302)	$102,846	$384	$(570)	$102,660

(Thousands)	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Segment Assets:									
At December 31, 2018	$1,691,903	$1,860,220	$538,551	$1,995,606	$64,790	$6,151,070	$78,560	$(42,702)	$6,186,928
At September 30, 2018	$1,568,563	$1,848,180	$533,608	$1,921,971	$50,971	$5,923,293	$78,109	$35,084	$6,036,486

Quarter Ended December 31, 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	$139,141	$53,310	$170	$187,089	$38,636	$418,346	$1,096	$213	$419,655
Intersegment Revenues	$—	$21,985	$23,665	$2,182	$126	$47,958	$—	$(47,958)	$—
Segment Profit: Net Income (Loss)	$106,698	$38,462	$45,400	$20,993	$1,046	$212,599	$(719)	$(13,226)	$198,654

Note 9 – Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

	Retirement Plan	Other Post-Retirement

Three Months Ended December 31,	2018	2017	Benefits 2018	2017
Service Cost	$2,120	$2,480	$380	$458
Interest Cost	9,594	8,252	4,286	3,700
Expected Return on Plan Assets	(15,591)	(15,429)	(7,539)	(7,871)
Amortization of Prior Service Cost (Credit)	206	235	(107)	(107)
Amortization of Losses	8,024	9,301	1,490	2,639
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	819	1,721	3,971	3,608
Net Periodic Benefit Cost	$5,172	$6,560	$2,481	$2,427

(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.

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Employer Contributions. During the three months ended December 31, 2018, the Company contributed $29.2 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $0.7 million to its VEBA trusts for its other post-retirement benefits. In the remainder of 2019, the Company may contribute up to $5.0 million to the Retirement Plan and the Company expects its contributions to the VEBA trusts to be in the range of $2.0 million to $3.0 million.

Note 10 – 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. The order provided for a return on equity of 8.7%.

On August 9, 2018, in response to the enactment of the 2017 Tax Reform Act, the NYPSC issued an Order Determining Rate Treatment of Tax Changes directing utilities to make compliance filings effective October 1, 2018 to begin providing sur-credits to customers reflecting tax savings associated with the 2017 Tax Reform Act. In compliance with that order, Distribution Corporation filed the necessary tariff amendments to implement the sur-credit effective October 1, 2018. At December 31, 2018, a refund provision of $8.6 million associated with the impact of the 2017 Tax Reform Act in the New York jurisdiction was included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. Refer to Note 5 - 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.

In response to the issuance of the 2017 Tax Reform Act, the PaPUC issued an Order to Distribution Corporation on May 17, 2018, requiring that Distribution Corporation file a tariff supplement establishing temporary rates to implement refunds of 2.2% on customer rates beginning July 1, 2018. In compliance with the May 17, 2018 PaPUC Order, Distribution Corporation filed a subsequent tariff supplement adjusting the negative surcharge in connection with the start of its new fiscal year, with the new rates effective October 1, 2018. All rates are subject to reconciliation. At December 31, 2018, a refund provision of $4.4 million associated with the impact of the 2017 Tax Reform Act in the Pennsylvania jurisdiction was included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. Refer to Note 5 - 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. In response to the FERC’s July 2018 Final Rule in RM18-11-000, et. al (Order No. 849), on December 6, 2018, Supply Corporation filed its Form 501-G, which addresses the impact of the 2017 Tax Reform Act, and advised the Commission that it would make a Section 4 rate filing no later than July 31, 2019, thereby obviating the need for FERC to take any further action. Refer to Note 5 - Income Taxes for further discussion of the 2017 Tax Reform Act.

Empire filed a Section 4 rate case on June 29, 2018, proposing rate increases to be effective August 1, 2018. Empire and its customers reached a settlement in principle in December 2018, and Empire’s subsequent motion to put in place those interim settlement rates, effective January 1, 2019, was approved by FERC’s Chief Administrative Law Judge on

December 31, 2018. The settlement remains subject to FERC approval. The “black box” settlement provides for new, system-wide rates, and which, based on current contracts, is estimated to increase Empire’s revenues on a yearly basis by approximately $4.6 million. The settlement also provides new depreciation rates and a tiered transportation revenue sharing mechanism, beginning with Empire sharing 35% of transportation only revenues (net of certain excluded items) over $64.4 million up to Empire sharing 55% of those revenues over $68.4 million. Empire has also committed to undertake certain improvements to its bulletin board and will convene regular customer meetings to address these and other improvements. Under the settlement, Empire and the other parties may not file to change rates until March 31, 2021, except that Empire may make a filing (to be effective November 1, 2020) under limited circumstances for contract changes with a large customer. Empire must file a Section 4 rate case no later than May 1, 2025.

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

OVERVIEW

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

The Company is a diversified energy company engaged principally in the production, gathering, transportation, distribution and marketing of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current development activities are focused 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.

The Company's implementation of the 2017 Tax Reform Act had a significant impact on its financial statements. The effective tax rate for the quarter ended December 31, 2017 of negative 69.2% reflects a statutory rate of 24.5% as well as the impact of the remeasurement of the Company's accumulated deferred income taxes based upon the new tax rates established by the 2017 Tax Reform Act, which was recorded as a $111.0 million reduction to income tax expense during the quarter ended December 31, 2017. The effective tax rate for the quarter ended December 31, 2018 of 18.2% reflects a lower statutory rate of 21% as well as the impact of a $5.0 million reduction to income tax expense recorded during the quarter ended December 31, 2018. The $5.0 million reduction to income tax expense represents an adjustment to the fiscal 2018 remeasurement of the Company's accumulated deferred income taxes stemming from the 2017 Tax Reform Act. 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 5 — 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 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. On August 6, 2018, the FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. Rehearing requests have been filed at FERC. The Company remains committed to the project. In light of these pending legal actions and the need to complete necessary project development activities in advance of construction, the target in-service date for the project is expected to be no earlier than fiscal 2022. Approximately $76.5 million in costs have been incurred on this project through December 31, 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. For further discussion of the Northern Access project, refer to Item 1 at Note 7 — Commitments and Contingencies.

While legal proceedings continue on the Northern Access project, 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 FM100 Project, is currently in the pre-filing process at FERC and will upgrade 1950’s era pipeline in northwestern Pennsylvania and create approximately 330,000 Dth per day of additional transportation capacity on Supply Corporation’s system in Pennsylvania from a receipt point with NFG Midstream Clermont, LLC in McKean County, Pennsylvania to the Transcontinental Gas Pipe Line Company, LLC system at Leidy, Pennsylvania. The FM100 Project has a target in-service date in late calendar 2021 and a preliminary cost estimate of approximately $280 million. These and other projects are discussed in more detail in the Capital Resources and Liquidity section that follows.

From a rate perspective, Empire reached a settlement in principle with its customers in December 2018 with regard to Empire's Section 4 rate case. The settlement remains subject to FERC approval. Based on current contracts, the settlement, if approved, is estimated to increase Empire's revenues on a yearly basis by approximately $4.6 million. For further discussion, refer to Rate and Regulatory Matters below.

The Company also continues to grow its Exploration and Production segment. Seneca's proved reserves grew 17% during fiscal 2018 to a total of 2,523 Bcfe at September 30, 2018. During fiscal 2018, Seneca transitioned from operating two drilling rigs in Pennsylvania to three rigs. This increased drilling activity is expected to result in meaningful production and reserve growth in fiscal 2019. More detail regarding the Exploration and Production segment's capital expenditures in fiscal 2019 are discussed in the Capital Resources and Liquidity section that follows.

From a financing perspective, the Company expects to use cash on hand and cash from operations to meet its capital expenditure needs for fiscal 2019 and may issue short-term and/or long-term debt during fiscal 2019 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 2018 Form 10-K. There have been no material changes to that disclosure other than as set forth below. The information presented below updates and should be read in conjunction with the critical accounting estimates in that Form 10-K.

Oil and Gas Exploration and Development Costs. The Company, in its Exploration and Production segment, follows the full cost method of accounting for determining the book value of its oil and natural gas properties. In accordance with this methodology, the Company is required to perform a quarterly ceiling test. Under the ceiling test, the present value of future revenues from the Company's oil and gas reserves based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (the "ceiling") is compared with the book value of the Company's oil and gas properties at the balance sheet date. If the book value of the oil and gas properties exceeds the ceiling, a non-cash impairment charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. At December 31, 2018, the ceiling exceeded the book value of the oil and gas properties by approximately $776.3 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended December 31, 2018, based on posted Midway Sunset prices, was $66.88 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during the twelve months ended December 31, 2018, based on the quoted Henry Hub spot price for natural gas, was $3.10 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 December 31, 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 December 31, 2018 if natural gas prices were $0.25 per MMBtu lower than the average prices used at December 31, 2018, if crude oil prices were $5 per Bbl lower than the average prices used at December 31, 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 December 31, 2018 (all amounts are presented after-tax). In all cases, these price decreases would not have resulted in an impairment charge. 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	$5.00/Bbl	$0.25/MMBtu

	Decrease in Natural Gas Prices	Decrease in Crude Oil Prices	Decrease in Natural Gas Prices and $5.00/Bbl Decrease in Crude Oil Prices
Excess of Ceiling over Book Value under Sensitivity Analysis	$ 581.0	$ 741.7	$ 546.4

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 2018 Form 10-K.

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2017 Tax Reform Act. On December 22, 2017, 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 was required to use a blended tax rate for fiscal 2018.

The Company has completed the remeasurement of accumulated deferred income taxes in the December 31, 2018 financial statements under Staff Accounting Bulletin (SAB) 118. Any subsequent guidance or clarification related to the 2017 Tax Reform Act 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 5 — Income Taxes.

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $102.7 million for the quarter ended December 31, 2018 compared to earnings of $198.7 million for the quarter ended December 31, 2017. The decrease in earnings of $96.0 million is primarily a result of a decrease in favorable remeasurements of accumulated deferred income taxes of $5.0 million and $111.0 million recorded during the quarters ended December 31, 2018 and December 31, 2017, respectively, as a result of the 2017 Tax Reform Act, as discussed above. Excluding these remeasurements, earnings were up $10.0 million quarter over quarter. Additional discussion of earnings in each of the business segments, including the impact of the 2017 Tax Reform Act, can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

	Three Months Ended December 31,		
(Thousands)	2018	2017	Increase (Decrease)
Exploration and Production	$38,214	$106,698	$(68,484)
Pipeline and Storage	25,102	38,462	(13,360)
Gathering	14,183	45,400	(31,217)
Utility	25,649	20,993	4,656
Energy Marketing	(302)	1,046	(1,348)
Total Reportable Segments	102,846	212,599	(109,753)
All Other	384	(719)	1,103
Corporate	(570)	(13,226)	12,656
Total Consolidated	$102,660	$198,654	$(95,994)

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended December 31,		
(Thousands)	2018	2017	Increase (Decrease)
Gas (after Hedging)	$119,750	$98,115	$21,635

Oil (after Hedging)	35,264	40,214	(4,950)
Gas Processing Plant	975	1,065	(90)
Other	6,887	(253)	7,140
	$162,876	$139,141	$ 23,735

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Production Volumes

	Three Months Ended December 31, 2018	2017	Increase (Decrease)
Gas Production (MMcf)			
Appalachia	45,305	35,414	9,891
West Coast	502	695	(193)
Total Production	45,807	36,109	9,698
Oil Production (Mbbl)			
Appalachia	1	1	—
West Coast	571	672	(101)
Total Production	572	673	(101)

Average Prices

	Three Months Ended December 31, 2018	2017	Increase (Decrease)
Average Gas Price/Mcf			
Appalachia	$2.93	$2.35	$ 0.58
West Coast	$6.73	$5.00	$ 1.73
Weighted Average	$2.97	$2.40	$ 0.57
Weighted Average After Hedging	$2.61	$2.72	$ (0.11)
Average Oil Price/Bbl			
Appalachia	$66.31	$43.85	$ 22.46
West Coast	$65.71	$57.88	$ 7.83
Weighted Average	$65.71	$57.86	$ 7.85
Weighted Average After Hedging	$61.70	$59.79	$ 1.91

2018 Compared with 2017

Operating revenues for the Exploration and Production segment increased $23.7 million for the quarter ended December 31, 2018 as compared with the quarter ended December 31, 2017. Gas production revenue after hedging increased $21.6 million primarily due to a 9.7 Bcf increase in gas production partially offset by a $0.11 per Mcf decrease in the weighted average price of gas after hedging. The increase in production was primarily due to new Marcellus and Utica wells completed and connected to sales in the Western and Eastern Development Areas coupled with a decrease in price-related curtailments in Appalachia during the quarter ended December 31, 2018 as compared with the quarter ended December 31, 2017. In addition, other revenue increased $7.1 million primarily due to the impact of mark-to-market adjustments related to ineffectiveness on oil hedges. These increases to operating revenues were partially offset by a decrease in oil production revenue after hedging of $5.0 million. The decrease in oil production revenue was primarily due to a 101 Mbbl decrease in crude oil production partially offset by a $1.91 per Bbl increase in the weighted average price of oil after hedging. The decrease in crude oil production was largely due to lower production in the West Coast region as a result of the sale of Seneca’s Sespe properties in May 2018.

The Exploration and Production segment's earnings for the quarter ended December 31, 2018 were $38.2 million, a decrease of $68.5 million when compared with earnings of $106.7 million for the quarter ended December 31, 2017. The decrease in earnings was primarily attributable to the impact of the 2017 Tax Reform Act passed during the quarter ended December 31, 2017, which resulted in a remeasurement of the segment’s accumulated deferred income taxes that lowered prior quarter income tax expense ($77.3 million). A removal of a valuation allowance related to the 2017 Tax Reform Act during the quarter ended

December 31, 2018 resulted in an adjustment to the segment's remeasured accumulated deferred income taxes and lowered current quarter income tax expense ($1.0 million). The reduction in the Company's federal statutory rate from a blended 24.5% in fiscal 2018 to 21% in fiscal 2019 lowered income tax expense on current quarter earnings ($1.6 million), which was partially offset by the non-recurrence of a tax benefit realized in the quarter ended December 31, 2017 related to the blended tax rate impact on temporary differences ($1.3 million).

Additionally, earnings decreased due to lower natural gas prices after hedging ($3.6 million), lower crude oil production ($4.6 million), higher depletion expense ($5.5 million), higher production expenses ($2.2 million), higher other operating expenses ($1.1 million), and higher other taxes ($2.1 million). The increase in depletion expense, which is computed using the units of production method, was primarily due to the increase in production coupled with a $0.02 per Mcfe increase in the depletion rate. The increase in production expense was largely due to increased gathering and transportation costs in the Appalachian region partially offset by the aforementioned sale of Seneca's Sespe properties in May 2018 and sales of compressor units to Midstream Company in March 2018. The increase in other operating expenses was largely due to an increase in personnel and compensation costs. The increase in other taxes was primarily due to a higher Pennsylvania Impact Fee as a result of additional wells drilled and a higher average natural gas price for calendar 2018, which is the basis for the Impact Fee determination. These factors, which decreased earnings during the quarter ended December 31, 2018, were partially offset by higher natural gas production ($19.9 million), higher crude oil prices after hedging ($0.8 million), and the impact of mark-to-market adjustments related to hedging ineffectiveness ($5.5 million).

Pipeline and Storage

Pipeline and Storage Operating Revenues

(Thousands)	Three Months Ended December 31, 2018	2017	Increase (Decrease)
Firm Transportation	$55,714	$56,756	$ (1,042)
Interruptible Transportation	421	340	81
	56,135	57,096	(961)
Firm Storage Service	18,928	17,839	1,089
Interruptible Storage Service	1	19	(18)
Other	2,005	341	1,664
	$77,069	$75,295	$ 1,774

Pipeline and Storage Throughput

(MMcf)	Three Months Ended December 31, 2018	2017	Increase (Decrease)
Firm Transportation	191,901	206,701	(14,800)
Interruptible Transportation	916	882	34
	192,817	207,583	(14,766)

2018 Compared with 2017

Operating revenues for the Pipeline and Storage segment increased $1.8 million for the quarter ended December 31, 2018 as compared with the quarter ended December 31, 2017. The increase in operating revenues was primarily due to an increase in storage revenues of $1.1 million combined with an increase in other revenues of $1.7 million. The increase in storage revenues was due to 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 in the third quarter of fiscal 2018. The increase in other revenues was due to proceeds received by Supply Corporation related to a contract termination as a result of a shipper's bankruptcy. Partially offsetting these increases was a decrease in transportation revenues of $1.0 million due to a decline in demand charges for Supply Corporation's transportation services as a result of contract terminations and a decline in transportation revenues due to an Empire system transportation contract reaching its termination date in December 2018. For the remainder of fiscal 2019, the Pipeline and

Storage segment expects transportation revenues to be negatively impacted in an amount up to approximately $13.6 million as a result of this Empire system transportation contract termination. The contract was not renewed due to a change in market dynamics.

Transportation volume for the quarter ended December 31, 2018 decreased by 14.8 Bcf from the prior year's quarter. The decrease in transportation volume for the quarter 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 December 31, 2018 were $25.1 million, a decrease of $13.4 million when compared with earnings of $38.5 million for the quarter ended December 31, 2017. The decrease in earnings was primarily due to higher income tax expense ($11.7 million) combined with higher operating expenses ($3.0 million). Income tax expense was higher due to the remeasurement of accumulated deferred income taxes in the quarter ended December 31, 2017 as a result of the 2017 Tax Reform Act, recorded as a $14.1 million reduction to income tax expense in the prior year quarter, which did not recur in the quarter ended December 31, 2018. Partially offsetting this income tax increase was the current period earnings impact of the change in the federal tax rate from a blended rate of 24.5% in fiscal 2018 to 21% for fiscal 2019 ($0.8 million) combined with lower income tax expense ($1.6 million) primarily due to permanent differences related to stock awards during the quarter ended December 31, 2018. The increase in operating expenses primarily reflects an increase in compressor station costs, increased personnel costs and a reversal of reserve for preliminary project costs recorded in the quarter ended December 31, 2017 that did not recur. These earnings decreases were slightly offset by the earnings impact of higher operating revenues of $1.3 million, as discussed above, and a decrease in interest expense ($0.4 million). The decrease in interest expense was largely due to lower intercompany long-term borrowing interest rates for the Pipeline and Storage segment.

Gathering

Gathering Operating Revenues

(Thousands)	Three Months Ended December 31, 2018	2017	Increase (Decrease)
Gathering	$29,690	$23,802	$ 5,888
Processing and Other Revenues	—	33	(33)
	$29,690	$23,835	$ 5,855

Gathering Volume

	Three Months Ended December 31, 2018	2017	Increase (Decrease)
Gathered Volume - (MMcf)	54,688	43,162	11,526

2018 Compared with 2017

Operating revenues for the Gathering segment increased $5.9 million for the quarter ended December 31, 2018 as compared with the quarter ended December 31, 2017. The increase was primarily due to an 11.5 Bcf increase in gathered volumes. The 11.5 Bcf increase in gathered volume can be attributed to a net increase in Seneca's production quarter over quarter.

The Gathering segment’s earnings for the quarter ended December 31, 2018 were $14.2 million, a decrease of $31.2 million when compared with earnings of $45.4 million for the quarter ended December 31, 2017. The decrease in earnings was primarily attributable to the impact of the 2017 Tax Reform Act passed during the quarter ended December 31, 2017, which resulted in a remeasurement of the segment’s accumulated deferred income taxes that lowered prior quarter income tax expense ($34.9 million). A removal of a valuation allowance related to the 2017 Tax Reform Act during the quarter ended December 31, 2018 resulted in an adjustment to the segment’s remeasured accumulated deferred income taxes and lowered current quarter income tax expense ($0.5 million). The reduction in the Company’s federal statutory rate from a blended 24.5% in fiscal 2018 to 21% in fiscal 2019 lowered income tax expense on current quarter earnings ($0.6 million), which was partially offset by the non-recurrence

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of a tax benefit realized in the quarter ended December 31, 2017 related to the blended tax rate impact on temporary differences ($0.8 million). Additionally, earnings decreased due to higher operating expense ($0.5 million) and higher depreciation expense ($0.4 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. Depreciation expense increased due to higher plant balances, primarily at the Trout Run and Clermont gathering systems. The earnings decrease was slightly offset by the impact of higher gathering revenues ($4.4 million), as discussed above.

Utility

Utility Operating Revenues

(Thousands)	Three Months Ended December 31, 2018	2017	Increase (Decrease)
Retail Sales Revenues:			
Residential	$165,333	$134,739	$30,594
Commercial	22,742	19,633	3,109
Industrial	1,493	872	621
	189,568	155,244	34,324
Transportation	35,950	36,309	(359)
Off-System Sales	—	41	(41)
Other	(2,861)	(2,323)	(538)
	$222,657	$189,271	$33,386

Utility Throughput

(MMcf)	Three Months Ended December 31, 2018	2017	Increase (Decrease)
Retail Sales:			
Residential	19,780	17,847	1,933
Commercial	2,846	2,596	250
Industrial	204	144	60
	22,830	20,587	2,243
Transportation	22,270	21,427	843
Off-System Sales	—	22	(22)
	45,100	42,036	3,064

Degree Days

Three Months Ended December 31,	Normal	2018	2017	Percent Colder (Warmer) Than Normal[1]	Prior Year[1]
Buffalo	2,253	2,325	2,227	3.2 %	4.4 %
Erie	2,044	2,030	2,029	(0.7)%	— %

(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 $33.4 million for the quarter ended December 31, 2018 as compared with the quarter ended December 31, 2017. The increase largely resulted from a $34.3 million increase in retail gas sales revenues.

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The increase in retail gas sales revenue was largely a result of an increase in the cost of gas sold (per Mcf), higher throughput volumes (due primarily to impacts of higher usage and an increase in retail accounts from transportation customer migration), and $1.2 million of revenues related to the system modernization tracker that commenced during the quarter ended December 31, 2018 in the segment's New York service territory. The tracker, which was approved by the NYPSC, is designed to recover increased investment in utility system modernization. These increases were partially offset by a $0.4 million decrease in transportation revenues and a $0.5 decrease in other revenues due to the impact of regulatory adjustments. The decline in transportation revenues was primarily due to the migration of residential customers from transportation sales to retail.

The Utility segment's earnings for the quarter ended December 31, 2018 were $25.6 million, an increase of $4.6 million when compared with earnings of $21.0 million for the quarter ended December 31, 2017. The increase in earnings was largely attributable to the impacts of higher usage and weather on residential and commercial customer margins ($1.7 million), the system modernization tracker revenues discussed above ($0.9 million), lower interest expense ($0.7 million), and the net impact of the 2017 Tax Reform Act, as discussed below. The decrease in interest expense was largely due to lower interest rates on intercompany long-term borrowings resulting from the Company's early redemption of 8.75% notes that were set to mature in May 2019. The increase in revenues resulting from higher gas costs do not have any impact on earnings as the revenues are matched against purchased gas sold.

The 2017 Tax Reform Act lowered the Company's statutory federal income tax rate from a blended 24.5% in fiscal 2018 to 21% in fiscal 2019, which resulted in lower income tax expense ($1.0 million). In accordance with NYPSC and PaPUC regulatory orders, the Utility segment has been recording a refund provision to return the net effect of the lower income tax rate to the segment's customers. The estimated refund provision recorded for the quarter ended December 31, 2018, was $0.5 million lower than the refund provision recorded for the quarter ended December 31, 2017, benefiting current quarter earnings by $0.4 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 December 31, 2018, the WNC reduced earnings by approximately $0.8 million, as the weather was colder than normal. For the quarter ended December 31, 2017 the WNC increased earnings by approximately $0.9 million, as the weather was warmer than normal.

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended December 31,		
(Thousands)	2018	2017	Increase (Decrease)
Natural Gas (after Hedging)	$52,412	$38,730	$ 13,682
Other	—	32	(32)
	$52,412	$38,762	$ 13,650

Energy Marketing Volume

	Three Months Ended December 31,	
	2018	2017

			Increase (Decrease)
Natural Gas – (MMcf)	12,419	11,979	440

2018 Compared with 2017

Operating revenues for the Energy Marketing segment increased $13.7 million for the quarter ended December 31, 2018 as compared with the quarter ended December 31, 2017. The increase was primarily due to an increase in gas sales revenue due to a higher average price of natural gas period over period. An increase in volume sold to retail customers as a result of colder weather and additional business from new customers also contributed to the increase in operating revenues.

The Energy Marketing segment recorded a loss of $0.3 million for the quarter ended December 31, 2018, a decrease of $1.3 million when compared with earnings of $1.0 million for the quarter ended December 31, 2017. This decrease was primarily attributable to lower margin of $1.8 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 partially offset by lower income tax expense of $0.5 million. Income tax expense was lower primarily due to an adjustment to the remeasurement of accumulated deferred income taxes as a result of the 2017 Tax Reform Act, which was recorded as a $0.2 million reduction to income tax expense during the quarter ended December 31, 2018, compared to the initial remeasurement of accumulated deferred income taxes recorded during the quarter ended December 31, 2017, which was recorded as a $0.2 million increase to income tax expense.

Corporate and All Other

2018 Compared with 2017

Corporate and All Other operations had a loss of $0.2 million for the quarter ended December 31, 2018, which was $13.7 million lower than the loss of $13.9 million for the quarter ended December 31, 2017. The decrease in the loss was primarily attributable to the impact of the 2017 Tax Reform Act passed during the quarter ended December 31, 2017, which resulted in a remeasurement of accumulated deferred income taxes that increased prior quarter income tax expense ($15.1 million). A removal of a valuation allowance related to the 2017 Tax Reform Act during the quarter ended December 31, 2018 resulted in an adjustment to the Corporate and All Other category's remeasured accumulated deferred income taxes and lowered current quarter income tax expense ($3.3 million). This increase in earnings was partially offset by the impact of unrealized losses on investments in equity securities ($5.0 million) for the quarter ended December 31, 2018. Unrealized gains and losses on investments in equity securities are now recognized in earnings following the adoption of authoritative accounting guidance effective October 1, 2018. These unrealized gains and losses had been previously recorded as other comprehensive income.

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

Interest on long-term debt decreased $2.6 million for the quarter ended December 31, 2018 as compared with the quarter ended December 31, 2017. The decrease is due to a decrease in the weighted average interest rate on long-term debt outstanding. The Company issued $300 million of 4.75% notes in August 2018 and repaid $250 million of 8.75% notes in September 2018.

CAPITAL RESOURCES AND LIQUIDITY

The Company’s primary sources of cash during the three-month periods ended December 31, 2018 and December 31, 2017 consisted of cash provided by operating activities.

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.

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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 $104.4 million for the three months ended December 31, 2018, an increase of $6.9 million compared with $97.5 million provided by operating activities for the three months ended December 31, 2017. The increase in cash provided by operating activities reflects lower interest payments on long-term debt, primarily in the Utility and Pipeline and Storage segments, offset by lower cash from operations in the Utility segment 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 $174.9 million during the three months ended December 31, 2018 and $126.5 million during the three months ended December 31, 2017. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Three Months Ended December 31, (Millions)	2018		2017		Increase (Decrease)
Exploration and Production:					
Capital Expenditures	$120.2	(1)	$74.7	(2)	$ 45.5
Pipeline and Storage:					
Capital Expenditures	30.0	(1)	22.3	(2)	7.7
Gathering:					
Capital Expenditures	8.8	(1)	12.9	(2)	(4.1)
Utility:					
Capital Expenditures	15.9	(1)	16.5	(2)	(0.6)
All Other:					
Capital Expenditures	—		0.1		(0.1)
	$174.9		$126.5		$ 48.4

(1) At December 31, 2018, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $66.1 million, $12.9 million, $4.4 million and $2.8 million, respectively, of non-cash capital expenditures. At September 30, 2018, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $51.3 million, $21.9 million, $6.1 million and $9.5 million, respectively, of non-cash capital expenditures.

(2) At December 31, 2017, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $37.1 million, $10.7 million, $4.7 million and $3.6 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.

Exploration and Production

The Exploration and Production segment capital expenditures for the three months ended December 31, 2018 were primarily well drilling and completion expenditures and included approximately $114.7 million for the Appalachian region (including $49.8 million in the Marcellus Shale area and $63.5 million in the Utica Shale area) and $5.5 million for the West Coast region. These amounts included approximately $61.1 million spent to develop proved undeveloped reserves.

The Exploration and Production segment capital expenditures for the three months ended December 31, 2017 were primarily well drilling and completion expenditures and included approximately $70.6 million for the Appalachian region (including $58.7 million in the Marcellus Shale area) and $4.1 million for the West Coast region. These amounts included approximately $40.7 million spent to develop proved undeveloped reserves.

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Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the three months ended December 31, 2018 were primarily 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 three months ended December 31, 2018 include expenditures related to Supply Corporation's Line N to Monaca Project ($1.1 million), as discussed below. The Pipeline and Storage capital expenditures for the three months ended December 31, 2017 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 three months ended December 31, 2017 include expenditures related to Supply Corporation's Line D Expansion Project ($12.4 million).

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 completed and continue to pursue 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 (the "Northern Access project"). The Northern Access project would provide an outlet to Dawn-indexed markets in Canada and to the TGP line serving the U.S. Northeast. The Northern Access project involves the construction of approximately 99 miles of largely 24" pipeline and approximately 27,500 horsepower of compression on the two systems. 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. On August 6, 2018, the FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. Rehearing requests have been filed at FERC. The Company remains committed to the project. In light of these pending legal actions and the need to complete necessary project development activities in advance of construction, the target in-service date for the project is expected to be no earlier than fiscal 2022. The Company will update the $500 million preliminary cost estimate when there is further clarity on that date. As of December 31, 2018, approximately $76.5 million has been spent on the Northern Access 2016 project, including $23.4 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.

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 December 31, 2018, approximately $4.7 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at December 31, 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 ("Line N to Monaca Project"). 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 July 1, 2019 at an estimated capital cost of approximately $24.3 million. As of December 31, 2018, approximately $3.3 million has been capitalized as Construction Work in Progress for this project.

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 330,000 Dth per day of additional transportation capacity 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 become part of a Transco expansion project ("Leidy South") that will create incremental transportation capacity to Transco Zone 6 markets. Seneca is the anchor shipper on Leidy South, 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 FM100 Project has a target in-service date in late calendar 2021 and a preliminary cost estimate of approximately $280 million. As of December 31, 2018, approximately $1.6 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at December 31, 2018.

Gathering

The majority of the Gathering segment capital expenditures for the three months ended December 31, 2018 were for the continued buildout of Midstream Company’s Trout Run Gathering System, Midstream Company's Clermont Gathering System and Midstream Company's Wellsboro Gathering System, as discussed below. The majority of the Gathering segment capital expenditures for the three months ended December 31, 2017 were for the continued buildout of the Clermont Gathering System and the Trout Run Gathering System.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Company, continues to develop an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The Clermont Gathering System was initially placed in service in July 2014. The current system consists of approximately 78 miles of backbone and in-field gathering pipelines. The total cost estimate for the continued buildout will be dependent on the nature and timing of Seneca's long-term plans. As of December 31, 2018, approximately $299.2 million has been spent on the Clermont Gathering System, including approximately $3.0 million spent during the three months ended December 31, 2018, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 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 December 31, 2018, approximately $208.1 million has been spent on the Trout Run Gathering System, including approximately $1.3 million spent during the three months ended December 31, 2018, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 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 December 31, 2018, the Company has spent approximately $13.4 million in costs related to this project, including approximately $4.0 million spent during the three months ended December 31, 2018, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2018.

Utility

The majority of the Utility segment capital expenditures for the three months ended December 31, 2018 and December 31, 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 2019 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.

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

Financing Cash Flow

The Company did not have any consolidated short-term debt outstanding at December 31, 2018 or September 30, 2018, nor was there any short-term debt outstanding during the quarter ended December 31, 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 October 25, 2018, the Company entered into a Fourth Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of 12 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through October 25, 2023. The Company also has an uncommitted line of credit with a financial institution for general corporate purposes. Borrowings under this uncommitted line of credit would be made at competitive market rates. The uncommitted credit line is revocable at the option of the financial institution and is reviewed on an annual basis. The Company anticipates that its uncommitted line of credit generally will be renewed or substantially replaced by a similar line. Other financial institutions may also provide the Company with uncommitted or discretionary lines of credit in the future.

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. For purposes of calculating the debt to capitalization ratio, the Company's total capitalization will be increased by adding back 50% of the aggregate after-tax amount of non-cash charges directly arising from any ceiling test impairment occurring on or after July 1, 2018, not to exceed $250 million. At December 31, 2018, the Company’s debt to capitalization ratio (as calculated under the facility) was .51. The constraints specified in the Credit Agreement would have permitted an additional $1.66 billion in short-term and/or long-term debt to be outstanding at December 31, 2018 (further limited by the indenture covenants discussed below) before the Company’s debt to capitalization ratio exceeded .65.

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

The Credit Agreement contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of December 31, 2018, the Company did not have any debt outstanding under the Credit Agreement.

None of the Company's long-term debt as of December 31, 2018 and September 30, 2018 had a maturity date within the following twelve-month period.

During the quarter ended December 31, 2017, the Company redeemed $300.0 million of the Company's 6.50% notes that were scheduled to mature in April 2018. The Company redeemed those notes on October 18, 2017 for $307.0 million, plus accrued interest.

The Company’s embedded cost of long-term debt was 4.69% and 5.17% at December 31, 2018 and December 31, 2017, respectively.

Under the Company’s existing indenture covenants at December 31, 2018, the Company would have been permitted to issue up to a maximum of $874.0 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

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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 4.6%) of the Company’s long-term debt (as of December 31, 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 $45.1 million. These leases have been entered into for the use of compressors, drilling rigs, buildings and other items and are accounted for as operating leases.

OTHER MATTERS

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

During the three months ended December 31, 2018, the Company contributed $29.2 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $0.7 million to its VEBA trusts for its other post-retirement benefits. In the remainder of 2019, the Company may contribute up to $5.0 million to the Retirement Plan and the Company expects its contributions to VEBA trusts to be in the range of $2.0 million to $3.0 million.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets 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

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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 December 31, 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 2018 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. Briefs were filed and the Appellate Division heard oral arguments on January 16, 2019. The Company awaits the Court’s decision and 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. On August 9, 2018, the NYPSC issued an Order Determining Rate Treatment of Tax Changes (“August 9, 2018 Order”) in this proceeding directing utilities to make compliance filings effective October 1, 2018 to begin providing sur-credits to customers reflecting tax savings associated with the 2017 Tax Reform Act. In compliance with that order, Distribution Corporation filed the necessary tariff amendments to implement the sur-credit effective October 1, 2018 subject to full reservation of rights. On November 30, 2018, Distribution Corporation filed an appeal with New York State Supreme Court, Albany County, seeking review of the August 9, 2018 Order. The appeal contends that the August 9, 2018 Order was arbitrary and capricious, and impermissibly engaged in single-issue ratemaking by refusing to allow Distribution Corporation recovery for the improvements to the Company’s imputed equity ratio resulting from the recent federal tax rate reduction. The Company cannot predict the outcome of the appeal at this time. 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. That petition sought certain relief including recovery for the improvements to the Company's imputed equity ratio. On November 21, 2018, the NYPSC issued an order denying the petition, and Distribution Corporation is currently evaluating its legal options concerning this order. Refer to Item 1 at Note 5 - 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.

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In response to the issuance of the 2017 Tax Reform Act, the PaPUC issued an Order to Distribution Corporation on May 17, 2018, 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 filed the necessary tariff supplement to implement such refunds effective July 1, 2018. In compliance with the May 17, 2018 PaPUC Order, Distribution Corporation filed a subsequent tariff supplement adjusting the negative surcharge in connection with the start of its new fiscal year, with the new rates effective October 1, 2018. All rates are subject to reconciliation. Refer to Item 1 at Note 5 - 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. In response to the FERC’s July 2018 Final Rule in RM18-11-000, et. al (Order No. 849), on December 6, 2018, Supply Corporation filed its Form 501-G, which addresses the impact of the 2017 Tax Reform Act, and advised the Commission that it would make a Section 4 rate filing no later than July 31, 2019, thereby obviating the need for FERC to take any further action. Refer to Item 1 at Note 5 - Income Taxes for further discussion of the 2017 Tax Reform Act.

Empire filed a Section 4 rate case on June 29, 2018, proposing rate increases to be effective August 1, 2018. Empire and its customers reached a settlement in principle in December 2018, and Empire’s subsequent motion to put in place those interim settlement rates, effective January 1, 2019, was approved by FERC’s Chief Administrative Law Judge on December 31, 2018. The settlement remains subject to FERC approval. The “black box” settlement provides for new, system-wide rates, and which, based on current contracts, is estimated to increase Empire’s revenues on a yearly basis by approximately $4.6 million. The settlement also provides new depreciation rates and a tiered transportation revenue sharing mechanism, beginning with Empire sharing 35% of transportation only revenues (net of certain excluded items) over $64.4 million up to Empire sharing 55% of those revenues over $68.4 million. Empire has also committed to undertake certain improvements to its bulletin board and will convene regular customer meetings to address these and other improvements. Under the settlement, Empire and the other parties may not file to change rates until March 31, 2021, except that Empire may make a filing (to be effective November 1, 2020) under limited circumstances for contract changes with a large customer. Empire must file a Section 4 rate case no later than May 1, 2025.

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 7 — 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 from 1990 levels. Additionally, the plan targets that 50% of electric generation must come from renewable energy sources, in addition to a 600 trillion Btu increase in statewide energy efficiency from 2012 levels, both by 2030. Similarly, Pennsylvania has a methane reduction framework for the oil and gas industry which has resulted 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

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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. Changing market conditions and new regulatory requirements, as well as unanticipated or inconsistent application of existing laws and regulations by administrative agencies, make it difficult to predict a long-term business impact across twenty or more years.

New Authoritative Accounting and Financial Reporting Guidance

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

Safe Harbor for Forward-Looking Statements

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

1. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;
2. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;
3. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration

and production activities such as hydraulic fracturing;

4. 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

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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 December 31, 2018.

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Changes in Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended December 31, 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 7 — 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 10 — Regulatory Matters.

Item 1A. Risk Factors
The risk factors in Item 1A of the Company's 2018 Form 10-K have not materially changed.

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

On October 1, 2018, the Company issued a total of 7,020 unregistered shares of Company common stock to nine non-employee directors of the Company then serving on the Board of Directors of the Company, 780 shares to each such director. All of these unregistered shares were issued under the Company's 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors' services during the quarter ended December 31, 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]
Oct. 1 - 31, 2018	9,238	$55.99	—	6,971,019
Nov. 1 - 30, 2018	12,536	$52.69	—	6,971,019
Dec. 1 - 31, 2018	155,470	$54.92	—	6,971,019
Total	177,244	$54.82	—	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 December 31, 2018, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 177,244 shares purchased other than through a publicly announced share repurchase program, 28,784 were purchased for the Company's 401(k) plans and 148,460 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.

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Item 6. Exhibits

Exhibit Number	Description of Exhibit
10.1	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan.
10.2	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan.
•	Fourth Amended and Restated Credit Agreement, dated as of October 25, 2018, among the Company, the Lenders Party Thereto, and JP Morgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 8-K dated October 31, 2018).
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statements of Income for the Twelve Months Ended December 31, 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 months ended December 31, 2018 and 2017, (ii) the Consolidated Statements of Comprehensive Income for the three months ended December 31, 2018 and 2017, (iii) the Consolidated Balance Sheets at December 31, 2018 and September 30, 2018, (iv) the Consolidated Statements of Cash Flows for the three months ended December 31, 2018 and 2017 and (v) the Notes to Condensed Consolidated Financial Statements.

• Incorporated herein by reference as indicated.

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

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SIGNATURES

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

NATIONAL FUEL GAS COMPANY
(Registrant)

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

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

Date: February 1, 2019