UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

☑ **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2021

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)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, par value $1.00 per share	NFG	New York Stock Exchange

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 (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically 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 ☑ 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.

Large Accelerated Filer	☑	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 ☑

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: Common stock, par value $1.00 per share, outstanding at July 31, 2021: 91,181,154 shares.

GLOSSARY OF TERMS

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

National Fuel Gas Companies

Company	The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
Midstream Company	National Fuel Gas Midstream Company, LLC
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
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	Securities and Exchange Commission

Other

2020 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2020
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.
CLCPA	Legislation referred to as the "Climate Leadership & Community Protection Act," enacted by the State of New York on July 18, 2019.
Degree day	A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.

Derivative	A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, forward contracts, options, no cost collars and swaps.
Development costs	Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act.
Dth	Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act	Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets	Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploration costs	Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
Exploratory well	A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.
FERC 7(c) application	An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.
Firm transportation and/or storage	The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.
GAAP	Accounting principles generally accepted in the United States of America
Goodwill	An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.
Hedging	A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.
Hub	Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.
ICE	Intercontinental Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Interruptible transportation and/or storage	The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.
LDC	Local distribution company
LIBOR	London Interbank Offered Rate
LIFO	Last-in, first-out
Marcellus Shale	A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.
Mbbl	Thousand barrels (of oil)
Mcf	Thousand cubic feet (of natural gas)
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
MDth	Thousand decatherms (of natural gas)
MMBtu	Million British thermal units (heating value of one decatherm of natural gas)
MMcf	Million cubic feet (of natural gas)

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.
OPEB	Other Post-Employment Benefit
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.

INDEX	Page

• The Company has nothing to report under this item.

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

Part I. Financial Information

Item 1. Financial Statements

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

(Thousands of U.S. Dollars, Except Per Common Share Amounts)	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Nine Months Ended June 30, 2021	Nine Months Ended June 30, 2020
INCOME				
Operating Revenues:				
Utility and Energy Marketing Revenues	$ 126,933	$ 139,661	$ 587,247	$ 650,320
Exploration and Production and Other Revenues	209,618	132,338	621,933	456,073
Pipeline and Storage and Gathering Revenues	57,846	51,020	177,491	151,908
	394,397	323,019	1,386,671	1,258,301
Operating Expenses:				
Purchased Gas	18,737	29,121	177,018	239,663
Operation and Maintenance:				
Utility and Energy Marketing	42,577	43,950	139,521	138,931
Exploration and Production and Other	43,112	32,404	127,033	109,056
Pipeline and Storage and Gathering	31,239	24,298	87,471	77,488
Property, Franchise and Other Taxes	24,492	21,381	71,259	67,268
Depreciation, Depletion and Amortization	84,170	73,232	251,632	226,062
Impairment of Oil and Gas Producing Properties	—	18,236	76,152	195,997
	244,327	242,622	930,086	1,054,465
Gain on Sale of Timber Properties	—	—	51,066	—
Operating Income	150,070	80,397	507,651	203,836
Other Income (Expense):				
Other Income (Deductions)	(2,028)	2,547	(15,078)	(17,971)
Interest Expense on Long-Term Debt	(30,220)	(27,140)	(111,296)	(77,853)
Other Interest Expense	(1,012)	(1,420)	(4,630)	(4,863)
Income Before Income Taxes	116,810	54,384	376,647	103,149
Income Tax Expense	30,335	13,134	99,962	81,376
Net Income Available for Common Stock	86,475	41,250	276,685	21,773
EARNINGS REINVESTED IN THE BUSINESS				
Balance at Beginning of Period	1,100,718	1,176,870	991,630	1,272,601
	1,187,193	1,218,120	1,268,315	1,294,374
Dividends on Common Stock	(41,493)	(40,470)	(122,615)	(115,774)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	—	(950)
Balance at June 30	$ 1,145,700	$ 1,177,650	$ 1,145,700	$ 1,177,650
Earnings Per Common Share:				
Basic:				
Net Income Available for Common Stock	$ 0.95	$ 0.47	$ 3.04	$ 0.25
Diluted:				
Net Income Available for Common Stock	$ 0.94	$ 0.47	$ 3.02	$ 0.25
Weighted Average Common Shares Outstanding:				
Used in Basic Calculation	91,172,683	87,966,289	91,113,973	86,966,448
Used in Diluted Calculation	91,762,898	88,323,699	91,642,849	87,346,362
Dividends Per Common Share:				
Dividends Declared	$ 0.455	$ 0.445	$ 1.345	$ 1.315

See Notes to Condensed Consolidated Financial Statements

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

(Thousands of U.S. Dollars)	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Nine Months Ended June 30, 2021	Nine Months Ended June 30, 2020
Net Income Available for Common Stock	$ 86,475	$ 41,250	$ 276,685	$ 21,773
Other Comprehensive Income (Loss), Before Tax:				
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(201,498)	4,904	(187,850)	81,703
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	13,129	(36,347)	17,106	(68,733)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	—	1,313
Other Comprehensive Income (Loss), Before Tax	(188,369)	(31,443)	(170,744)	14,283
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(55,512)	1,341	(51,752)	22,315
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	3,617	(9,907)	4,713	(18,756)
Income Tax Benefit (Expense) on Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	—	363
Income Taxes – Net	(51,895)	(8,566)	(47,039)	3,922
Other Comprehensive Income (Loss)	(136,474)	(22,877)	(123,705)	10,361
Comprehensive Income (Loss)	$ (49,999)	$ 18,373	$ 152,980	$ 32,134

See Notes to Condensed Consolidated Financial Statements

Table of Contents

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of U.S. Dollars)	June 30, 2021	September 30, 2020
ASSETS		
Property, Plant and Equipment	$ 12,834,695	$ 12,351,852
Less - Accumulated Depreciation, Depletion and Amortization	6,649,038	6,353,785
	6,185,657	5,998,067
Assets Held for Sale, Net	—	53,424
Current Assets		
Cash and Temporary Cash Investments	118,012	20,541
Hedging Collateral Deposits	1,710	—
Receivables – Net of Allowance for Uncollectible Accounts of $32,322 and $22,810, Respectively	188,863	143,583
Unbilled Revenue	12,812	17,302
Gas Stored Underground	12,451	33,338
Materials, Supplies and Emission Allowances	53,740	51,877
Other Current Assets	51,969	47,557
	439,557	314,198
Other Assets		
Recoverable Future Taxes	118,883	118,310
Unamortized Debt Expense	11,016	12,297
Other Regulatory Assets	145,632	156,106
Deferred Charges	58,807	67,131
Other Investments	149,250	154,502
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	93,627	76,035
Fair Value of Derivative Financial Instruments	770	9,308
Other	—	81
	583,461	599,246
Total Assets	$ 7,208,675	$ 6,964,935

See Notes to Condensed Consolidated Financial Statements

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of U.S. Dollars)	June 30, 2021	September 30, 2020
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 91,172,701 Shares and 90,954,696 Shares, Respectively	$ 91,173	$ 90,955
Paid in Capital	1,012,703	1,004,158
Earnings Reinvested in the Business	1,145,700	991,630
Accumulated Other Comprehensive Loss	(238,462)	(114,757)
Total Comprehensive Shareholders' Equity	2,011,114	1,971,986
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,627,860	2,629,576
Total Capitalization	4,638,974	4,601,562
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	30,000
Accounts Payable	113,470	134,126
Amounts Payable to Customers	7,193	10,788
Dividends Payable	41,484	40,475
Interest Payable on Long-Term Debt	45,304	27,521
Customer Advances	—	15,319
Customer Security Deposits	19,272	17,199
Other Accruals and Current Liabilities	168,378	140,176
Fair Value of Derivative Financial Instruments	205,501	43,969
	600,602	459,573
Deferred Credits		
Deferred Income Taxes	742,638	696,054
Taxes Refundable to Customers	353,736	357,508
Cost of Removal Regulatory Liability	241,377	230,079
Other Regulatory Liabilities	182,430	161,573
Pension and Other Post-Retirement Liabilities	117,291	127,181
Asset Retirement Obligations	191,853	192,228
Other Deferred Credits	139,774	139,177
	1,969,099	1,903,800
Commitments and Contingencies (Note 8)	—	—
Total Capitalization and Liabilities	$ 7,208,675	$ 6,964,935

See Notes to Condensed Consolidated Financial Statements

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

(Thousands of U.S. Dollars)	Nine Months Ended June 30, 2021	Nine Months Ended June 30, 2020
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 276,685	$ 21,773
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Gain on Sale of Timber Properties	(51,066)	—
Impairment of Oil and Gas Producing Properties	76,152	195,997
Depreciation, Depletion and Amortization	251,632	226,062
Deferred Income Taxes	89,277	116,332
Premium Paid on Early Redemption of Debt	15,715	—
Stock-Based Compensation	12,296	9,716
Other	7,795	5,645
Change in:		
Receivables and Unbilled Revenue	(40,733)	4,045
Gas Stored Underground and Materials, Supplies and Emission Allowances	19,024	11,597
Unrecovered Purchased Gas Costs	—	2,246
Other Current Assets	(4,282)	49,312
Accounts Payable	7,474	(13,166)
Amounts Payable to Customers	(3,595)	14,755
Customer Advances	(15,319)	(12,483)
Customer Security Deposits	2,073	(984)
Other Accruals and Current Liabilities	23,154	6,774
Other Assets	5,839	(18,215)
Other Liabilities	(311)	4,464
Net Cash Provided by Operating Activities	671,810	623,870
INVESTING ACTIVITIES		
Capital Expenditures	(512,775)	(551,004)
Net Proceeds from Sale of Timber Properties	104,582	—
Acquisition of Upstream Assets and Midstream Gathering Assets	—	(27,050)
Other	11,223	4,126
Net Cash Used in Investing Activities	(396,970)	(573,928)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	(30,000)	(55,200)
Net Proceeds from Issuance of Long-Term Debt	495,267	493,108
Reduction of Long-Term Debt	(515,715)	—
Dividends Paid on Common Stock	(121,606)	(112,851)
Net Proceeds from Issuance (Repurchases) of Common Stock	(3,605)	161,704
Net Cash Provided by (Used in) Financing Activities	(175,659)	486,761
Net Increase in Cash, Cash Equivalents, and Restricted Cash	99,181	536,703
Cash, Cash Equivalents, and Restricted Cash at October 1	20,541	27,260
Cash, Cash Equivalents, and Restricted Cash at June 30	$ 119,722	$ 563,963
Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$ 81,485	$ 58,134

See Notes to Condensed Consolidated Financial Statements

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

Note 1 – Summary of Significant Accounting Policies

Principles of Consolidation. The Company consolidates all entities in which it has a controlling financial interest. All significant intercompany balances and transactions are eliminated. The Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

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

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments (which consist of only normally recurring adjustments, unless otherwise disclosed in this Form 10-Q) that are necessary for a fair statement of the results of operations for the reported periods. The consolidated financial statements and notes thereto, included herein, should be read in conjunction with the financial statements and notes for the years ended September 30, 2020, 2019 and 2018 that are included in the Company's 2020 Form 10-K. The consolidated financial statements for the year ended September 30, 2021 will be audited by the Company's independent registered public accounting firm after the end of the fiscal year.

The earnings for the nine months ended June 30, 2021 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2021. Most of the business of the Utility segment is seasonal in nature and is influenced by weather conditions. Due to the seasonal nature of the heating business in the Utility segment, earnings during the winter months normally represent a substantial part of the earnings that this business is expected to achieve for the entire fiscal year. The Company's business segments are discussed more fully in Note 9 – Business Segment Information.

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):

	Nine Months Ended June 30, 2021		Nine Months Ended June 30, 2020	
	Balance at October 1, 2020	**Balance at June 30, 2021**	**Balance at October 1, 2019**	**Balance at June 30, 2020**
Cash and Temporary Cash Investments	$ 20,541	$ 118,012	$ 20,428	$ 556,264
Hedging Collateral Deposits	—	1,710	6,832	7,699
Cash, Cash Equivalents, and Restricted Cash	$ 20,541	$ 119,722	$ 27,260	$ 563,963

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 composed 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.

Allowance for Uncollectible Accounts. The allowance for uncollectible accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The allowance is determined based on historical experience, the age of customer accounts, other specific information about customer accounts, and the economic environment. Account balances are charged off against the allowance twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered. As a result of the COVID-19 pandemic and associated increase in customer non-payment, the Company has increased the bad debt reserve to account for the modestly higher receivable balances.

Activity in the allowance for uncollectible accounts for the nine months ended June 30, 2021 are as follows (in thousands):

	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Add: Discounts on Purchased Receivables	Deduct: Net Accounts Receivable Written-Off	Balance at End of Period
Nine Months Ended June 30, 2021					
Allowance for Uncollectible Accounts	$ 22,810	$ 13,375	$ 1,097	$ 4,960	$ 32,322

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 $9.2 million at June 30, 2021, is reduced to zero by September 30 of each year as the inventory is replenished.

Materials, Supplies and Emission Allowances. The components of the Company's materials, supplies and emission allowances are as follows (in thousands):

	At June 30, 2021	At September 30, 2020
Materials and Supplies - at average cost	$ 35,060	$ 33,859
Emission Allowances	18,680	18,018
	$ 53,740	$ 51,877

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. The Company's capitalized costs relating to oil and gas producing activities, net of accumulated depreciation, depletion and amortization, were $1.8 billion at both June 30, 2021 and September 30, 2020.

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 $136.7 million and $148.1 million at June 30, 2021 and September 30, 2020, 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 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 non-cash impairment is required to be charged to earnings in that quarter. At June 30, 2021, the ceiling exceeded the book value of the oil and gas properties by approximately $409.8 million. The book value of the oil and gas properties exceeded the ceiling at December 31, 2020. As such, the Company recognized a non-cash, pre-tax impairment charge of $76.2 million for the quarter ended December 31, 2020. A deferred income tax benefit of $21.0

million related to the non-cash impairment charge was also recognized for the quarter ended December 31, 2020. In adjusting estimated future cash flows for hedging under the ceiling test at June 30, 2021, estimated future net cash flows were increased by $91.0 million.

The principal assets of the Utility, Pipeline and Storage and Gathering segments, consisting primarily of gas distribution pipelines, transmission pipelines, storage facilities, gathering lines and compressor stations, are recorded at historical cost. Despite the economic conditions arising from the COVID-19 pandemic, there were no indications of any impairments to property, plant and equipment in the Utility, Pipeline and Storage and Gathering segments at June 30, 2021. Management will continue to monitor the situation on a quarterly basis.

Accumulated Other Comprehensive Income (Loss). The components of Accumulated Other Comprehensive Income (Loss) and changes for the nine months ended June 30, 2021 and 2020, net of related tax effect, are as follows (amounts in parentheses indicate debits) (in thousands):

	Gains and Losses on Derivative Financial Instruments	Funded Status of the Pension and Other Post-Retirement Benefit Plans	Total
Three Months Ended June 30, 2021			
Balance at April 1, 2021	$ (12,096)	$ (89,892)	$ (101,988)
Other Comprehensive Gains and Losses Before Reclassifications	(145,986)	—	(145,986)
Amounts Reclassified From Other Comprehensive Income (Loss)	9,512	—	9,512
Balance at June 30, 2021	$ (148,570)	$ (89,892)	$ (238,462)
Nine Months Ended June 30, 2021			
Balance at October 1, 2020	$ (24,865)	$ (89,892)	$ (114,757)
Other Comprehensive Gains and Losses Before Reclassifications	(136,098)	—	(136,098)
Amounts Reclassified From Other Comprehensive Income (Loss)	12,393	—	12,393
Balance at June 30, 2021	$ (148,570)	$ (89,892)	$ (238,462)
Three Months Ended June 30, 2020			
Balance at April 1, 2020	$ 67,913	$ (86,830)	$ (18,917)
Other Comprehensive Gains and Losses Before Reclassifications	3,563	—	3,563
Amounts Reclassified From Other Comprehensive Income (Loss)	(26,440)	—	(26,440)
Balance at June 30, 2020	$ 45,036	$ (86,830)	$ (41,794)
Nine Months Ended June 30, 2020			
Balance at October 1, 2019	$ 34,675	$ (86,830)	$ (52,155)
Other Comprehensive Gains and Losses Before Reclassifications	59,388	—	59,388
Amounts Reclassified From Other Comprehensive Income (Loss)	(49,977)	—	(49,977)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	950	—	950
Balance at June 30, 2020	$ 45,036	$ (86,830)	$ (41,794)

In August 2017, the FASB issued authoritative guidance which changed 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 Company adopted this authoritative guidance effective October 1, 2019, recognizing a cumulative effect adjustment that decreased retained earnings by $1.0 million and increased accumulated other comprehensive income by the same amount.

Reclassifications Out of Accumulated Other Comprehensive Income (Loss). The details about the reclassification adjustments out of accumulated other comprehensive income (loss) for the nine months ended June 30, 2021 and 2020 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Income (Loss) Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss)				Affected Line Item in the Statement Where Net Income is Presented
	Three Months Ended June 30,		Nine Months Ended June 30,		
	2021	2020	2021	2020	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:					
Commodity Contracts	($13,281)	$36,726	($17,351)	$67,663	Operating Revenues
Commodity Contracts	—	(22)	—	1,890	Purchased Gas
Foreign Currency Contracts	152	(357)	245	(820)	Operating Revenues
	(13,129)	36,347	(17,106)	68,733	Total Before Income Tax
	3,617	(9,907)	4,713	(18,756)	Income Tax Expense
	($9,512)	$26,440	($12,393)	$49,977	Net of Tax

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

	At June 30, 2021	At September 30, 2020
Prepayments	$ 17,106	$ 12,851
Prepaid Property and Other Taxes	11,442	14,269
State Income Taxes Receivable	—	3,828
Regulatory Assets	23,421	16,609
	$ 51,969	$ 47,557

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

	At June 30, 2021	At September 30, 2020
Accrued Capital Expenditures	$ 55,632	$ 33,344
Regulatory Liabilities	29,786	44,890
Reserve for Gas Replacement	9,185	—
Liability for Royalty and Working Interests	23,619	15,665
Non-Qualified Benefit Plan Liability	14,460	14,460
Other	35,696	31,817
	$ 168,378	$ 140,176

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 and nine months ended June 30, 2021, 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 334,335 securities and 333,445 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2021, respectively. There were 513,428 securities and 513,180 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2020, respectively.

Stock-Based Compensation. The Company granted 309,470 performance shares during the nine months ended June 30, 2021. The weighted average fair value of such performance shares was $39.19 per share for the nine months ended June 30, 2021. Performance shares are an award constituting units denominated in common stock of the Company, the number of which may be adjusted over a performance cycle based upon the extent to which performance goals have been satisfied. Earned performance shares may be distributed in the form of shares of common stock of the Company, an equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company. The performance shares do not entitle the participant to receive dividends during the vesting period.

Half of the performance shares granted during the nine months ended June 30, 2021 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 nine months ended June 30, 2021 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 172,513 restricted stock units during the nine months ended June 30, 2021. The weighted average fair value of such restricted stock units was $37.98 per share for the nine months ended June 30, 2021. 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 restricted stock units do not entitle the participant to receive dividends during the vesting period. The accounting for 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. On October 1, 2020, the Company adopted authoritative guidance regarding the measurement of credit losses on financial assets measured at amortized cost. The new guidance requires financial assets measured at amortized cost to be presented at the net amount expected to be collected, which means that companies are required to recognize an allowance for credit losses for the difference between the amortized cost basis of the financial asset and the amount expected to be collected over the contractual life of the asset. Prior to adoption, the Company analyzed its financial assets measured at amortized cost, primarily trade receivables. The adoption of this guidance did not have a material impact to the Company's financial statements.

Note 2 – Asset Acquisitions and Divestitures

On December 10, 2020, the Company completed the sale of substantially all timber properties in Pennsylvania to Lyme Emporium Highlands III LLC and Lyme Allegheny Land Company II LLC for net proceeds of $104.6 million. At September 30, 2020, these assets, amounting to $53.4 million, which previously were recorded as Net Property, Plant and Equipment, were presented as Assets Held for Sale, Net on the Consolidated Balance Sheet. The assets were a component of the Company’s All Other category and did not have a major impact on the Company’s operations or financial results. After purchase price adjustments and transaction costs, a gain of $51.1 million was recognized on the sale of these assets. Since the sale did not represent a strategic shift in focus for the Company, the financial results associated with operating these assets as well as the gain on sale have not been reported as discontinued operations.

The sale of the timber properties completed a reverse like-kind exchange pursuant to Section 1031 of the Internal Revenue Code, as amended (“Reverse 1031 Exchange”). On July 31, 2020, the Company completed its acquisition of certain upstream assets and midstream gathering assets in Pennsylvania from SWEPI LP, a subsidiary of Royal Dutch Shell plc (“Shell”) for total consideration of $506.3 million. The purchase and sale agreement with Shell was structured, in part, as a Reverse 1031 Exchange. In connection with the Reverse 1031 Exchange, the Company, through a subsidiary, assigned the rights to acquire legal title to certain oil and natural gas properties to a Variable Interest Entity ("VIE") formed by an exchange accommodation titleholder. From July 31, 2020 to December 10, 2020, a subsidiary of the Company operated the properties pursuant to a lease agreement with the VIE. As the Company was deemed to be the primary beneficiary of the VIE, the VIE was included in the consolidated financial statements of the Company. Upon completion of the sale of the timber properties on December 10, 2020, the affected properties were conveyed to the Company and the VIE structure was terminated. Refer to Note B – Asset Acquisitions and Divestitures of the Company’s 2020 Form 10-K for additional information concerning the Company’s acquisition of certain upstream assets and midstream gathering assets from Shell.

Note 3 – Revenue from Contracts with Customers

The following tables provide a disaggregation of the Company's revenues for the quarter and nine months ended June 30, 2021 and 2020, presented by type of service from each reportable segment.

Quarter Ended June 30, 2021 (Thousands)

Revenues By Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Production of Natural Gas	$ 184,029	$ —	$ —	$ —	$ —	$ —	$ 184,029
Production of Crude Oil	37,695	—	—	—	—	—	37,695
Natural Gas Processing	732	—	—	—	—	—	732
Natural Gas Gathering Service	—	—	48,656	—	—	(48,068)	588
Natural Gas Transportation Service	—	63,107	—	20,201	—	(17,786)	65,522
Natural Gas Storage Service	—	20,646	—	—	—	(8,926)	11,720
Natural Gas Residential Sales	—	—	—	93,079	—	—	93,079
Natural Gas Commercial Sales	—	—	—	10,617	—	—	10,617
Natural Gas Industrial Sales	—	—	—	488	—	—	488
Natural Gas Marketing	—	—	—	—	1	(2)	(1)
Other	360	310	—	(437)	—	(84)	149
Total Revenues from Contracts with Customers	222,816	84,063	48,656	123,948	1	(74,866)	404,618
Alternative Revenue Programs	—	—	—	3,060	—	—	3,060
Derivative Financial Instruments	(13,281)	—	—	—	—	—	(13,281)
Total Revenues	$ 209,535	$ 84,063	$ 48,656	$ 127,008	$ 1	$ (74,866)	$ 394,397

Nine Months Ended June 30, 2021 (Thousands)

Revenues By Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Production of Natural Gas	$ 539,241	$ —	$ —	$ —	$ —	$ —	$ 539,241
Production of Crude Oil	95,783	—	—	—	—	—	95,783
Natural Gas Processing	2,056	—	—	—	—	—	2,056
Natural Gas Gathering Service	—	—	145,927	—	—	(144,317)	1,610
Natural Gas Transportation Service	—	192,580	—	88,736	—	(55,562)	225,754
Natural Gas Storage Service	—	62,394	—	—	—	(26,797)	35,597
Natural Gas Residential Sales	—	—	—	434,728	—	—	434,728
Natural Gas Commercial Sales	—	—	—	56,684	—	—	56,684
Natural Gas Industrial Sales	—	—	—	2,778	—	—	2,778
Natural Gas Marketing	—	—	—	—	651	(22)	629
Other	1,387	3,558	—	(6,568)	545	(291)	(1,369)
Total Revenues from Contracts with Customers	638,467	258,532	145,927	576,358	1,196	(226,989)	1,393,491
Alternative Revenue Programs	—	—	—	10,531	—	—	10,531
Derivative Financial Instruments	(17,351)	—	—	—	—	—	(17,351)
Total Revenues	$ 621,116	$ 258,532	$ 145,927	$ 586,889	$ 1,196	$ (226,989)	$ 1,386,671

Quarter Ended June 30, 2020 (Thousands)

Revenues By Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Production of Natural Gas	$ 76,831	$ —	$ —	$ —	$ —	$ —	$ 76,831
Production of Crude Oil	17,018	—	—	—	—	—	17,018
Natural Gas Processing	435	—	—	—	—	—	435
Natural Gas Gathering Service	—	—	33,299	—	—	(33,299)	—
Natural Gas Transportation Service	—	57,563	—	22,473	—	(20,445)	59,591
Natural Gas Storage Service	—	20,016	—	—	—	(8,802)	11,214
Natural Gas Residential Sales	—	—	—	93,853	—	—	93,853
Natural Gas Commercial Sales	—	—	—	10,264	—	—	10,264
Natural Gas Industrial Sales	—	—	—	616	—	—	616
Natural Gas Marketing	—	—	—	—	19,149	(341)	18,808
Other	218	234	—	(661)	1,015	(98)	708
Total Revenues from Contracts with Customers	94,502	77,813	33,299	126,545	20,164	(62,985)	289,338
Alternative Revenue Programs	—	—	—	492	—	—	492
Derivative Financial Instruments	36,726	—	—	—	(3,537)	—	33,189
Total Revenues	$ 131,228	$ 77,813	$ 33,299	$ 127,037	$ 16,627	$ (62,985)	$ 323,019

Nine Months Ended June 30, 2020 (Thousands)							
Revenues By Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Production of Natural Gas	$ 297,481	$ —	$ —	$ —	$ —	$ —	$ 297,481
Production of Crude Oil	84,949	—	—	—	—	—	84,949
Natural Gas Processing	1,838	—	—	—	—	—	1,838
Natural Gas Gathering Service	—	—	103,355	—	—	(103,355)	—
Natural Gas Transportation Service	—	169,469	—	95,112	—	(59,408)	205,173
Natural Gas Storage Service	—	58,966	—	—	—	(25,881)	33,085
Natural Gas Residential Sales	—	—	—	423,547	—	—	423,547
Natural Gas Commercial Sales	—	—	—	56,401	—	—	56,401
Natural Gas Industrial Sales	—	—	—	3,029	—	—	3,029
Natural Gas Marketing	—	—	—	—	89,662	(598)	89,064
Other	797	843	—	(7,509)	2,985	(216)	(3,100)
Total Revenues from Contracts with Customers	385,065	229,278	103,355	570,580	92,647	(189,458)	1,191,467
Alternative Revenue Programs	—	—	—	7,775	—	—	7,775
Derivative Financial Instruments	67,663	—	—	—	(8,604)	—	59,059
Total Revenues	$ 452,728	$ 229,278	$ 103,355	$ 578,355	$ 84,043	$ (189,458)	$ 1,258,301

The Company records revenue related to its derivative financial instruments in the Exploration and Production segment as well as in its NFR operations (included in the All Other category). The Company discontinued use of derivative financial instruments in its NFR operations upon completing the sale of its commercial and industrial contracts and certain other assets on August 1, 2020. The Company has been winding down its NFR operations since August 1, 2020 which has resulted in a significant reduction in natural gas marketing revenues as shown in the tables above. 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 authoritative guidance regarding revenue recognition since they are accounted for under other existing accounting guidance.

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: $47.8 million for the remainder of fiscal 2021; $183.1 million for fiscal 2022; $145.9 million for fiscal 2023; $125.3 million for fiscal 2024; $118.0 million for fiscal 2025; and $524.8 million thereafter.

Note 4 – Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of June 30, 2021 and September 30, 2020. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over-the-counter swaps combines gas and oil swaps because a significant number of the counterparties enter into both gas and oil swap agreements with the Company.

Recurring Fair Value Measures	At fair value as of June 30, 2021				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[(1)]	Total[(1)]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$ 104,861	$ —	$ —	$ —	$ 104,861
Hedging Collateral Deposits	1,710	—	—	—	1,710
Derivative Financial Instruments:					
Over the Counter Swaps – Gas and Oil	—	5,351	—	(5,351)	—
Foreign Currency Contracts	—	1,835	—	(1,829)	6
Other Investments:					
Balanced Equity Mutual Fund	34,849	—	—	—	34,849
Fixed Income Mutual Fund	70,388	—	—	—	70,388
Total	$ 211,808	$ 7,186	$ —	$ (7,180)	$ 211,814
Liabilities:					
Derivative Financial Instruments:					
Over the Counter Swaps – Gas and Oil	—	204,315	—	(5,351)	198,964
Over the Counter No Cost Collars – Gas	—	8,361	—	—	8,361
Foreign Currency Contracts	—	5	—	(1,829)	(1,824)
Total	$ —	$ 212,681	$ —	$ (7,180)	$ 205,501
Total Net Assets/(Liabilities)	$ 211,808	$ (205,495)	$ —	$ —	$ 6,313

Recurring Fair Value Measures	At fair value as of September 30, 2020				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[(1)]	Total[(1)]
Assets:					
Cash Equivalents – Money Market Mutual Funds	$ 12,285	$ —	$ —	$ —	$ 12,285
Derivative Financial Instruments:					
Over the Counter Swaps – Gas and Oil	—	36,418	—	(26,400)	10,018
Over the Counter No Cost Collars – Gas	—	—	—	(720)	(720)
Foreign Currency Contracts	—	259	—	(338)	(79)
Other Investments:					
Balanced Equity Mutual Fund	39,618	—	—	—	39,618
Fixed Income Mutual Fund	72,253	—	—	—	72,253
Common Stock – Financial Services Industry	639	—	—	—	639
Total	$ 124,795	$ 36,677	$ —	$ (27,458)	$ 134,014
Liabilities:					
Derivative Financial Instruments:					
Over the Counter Swaps – Gas and Oil	—	61,280	—	(26,400)	34,880
Over the Counter No Cost Collars – Gas	—	8,171	—	(720)	7,451
Foreign Currency Contracts	—	1,976	—	(338)	1,638
Total	$ —	$ 71,427	$ —	$ (27,458)	$ 43,969
Total Net Assets/(Liabilities)	$ 124,795	$ (34,750)	$ —	$ —	$ 90,045

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

Derivative Financial Instruments

The derivative financial instruments reported in Level 2 at June 30, 2021 and September 30, 2020 consist of natural gas price swap agreements, natural gas no cost collars, crude oil price swap agreements, and foreign currency contracts, all of which are used in the Company's Exploration and Production segment. Hedging collateral deposits of $1.7 million at June 30, 2021, which were associated with the price swap agreements, no cost collars and foreign currency contracts, have been reported in Level 1 at June 30, 2021. The fair value of the Level 2 price swap agreements and no cost collars 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 authoritative guidance for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At June 30, 2021, 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 June 30, 2021 and June 30, 2020, there were no assets or liabilities measured at fair value and classified as Level 3.

Note 5 – Financial Instruments

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

	June 30, 2021		September 30, 2020	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ 2,627,860	$ 2,913,834	$ 2,629,576	$ 2,778,556

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

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

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

	At June 30, 2021	At September 30, 2020
Life Insurance Contracts	$ 44,013	$ 41,992
Equity Mutual Fund	34,849	39,618
Fixed Income Mutual Fund	70,388	72,253
Marketable Equity Securities	—	639
	$ 149,250	$ 154,502

Investments in life insurance contracts are stated at their cash surrender values or net present value. Investments in an equity mutual fund and a fixed income mutual fund are stated at fair value based on quoted market prices with changes in fair value recognized in net income. The insurance contracts 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. The Company enters into over-the-counter no cost collars 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 duration of the Company's cash flow hedges does not typically exceed 5 years while the foreign currency forward contracts do not exceed 10 years.

The Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at June 30, 2021 and September 30, 2020. 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 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.

As of June 30, 2021, the Company had the following commodity derivative contracts (swaps and no cost collars) outstanding:

Commodity	Units	
Natural Gas	359.4	Bcf
Crude Oil	2,409,000	Bbls

As of June 30, 2021, the Company was hedging a total of $65.0 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts.

As of June 30, 2021, the Company had $205.5 million ($148.6 million after-tax) of net hedging losses included in the accumulated other comprehensive income (loss) balance. It is expected that $166.3 million ($120.2 million after-tax) of unrealized losses will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transactions are recorded in earnings.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended June 30, 2021 and 2020 (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) for the Three Months Ended June 30,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income for the Three Months Ended June 30,	
	2021	2020		2021	2020
Commodity Contracts	$ (202,114)	$ 3,273	Operating Revenue	$ (13,281)	$ 36,726
Commodity Contracts	—	(427)	Purchased Gas	—	(22)
Foreign Currency Contracts	616	2,058	Operating Revenue	152	(357)
Total	$ (201,498)	$ 4,904		$ (13,129)	$ 36,347

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2021 and 2020 (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) for the Nine Months Ended June 30,**		**Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income**	**Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income for the Nine Months Ended June 30,**	
	2021	2020		2021	2020
Commodity Contracts	$ (191,642)	$ 82,825	Operating Revenue	$ (17,351)	$ 67,663
Commodity Contracts	—	571	Purchased Gas	—	1,890
Foreign Currency Contracts	3,792	(1,693)	Operating Revenue	245	(820)
Total	$ (187,850)	$ 81,703		$ (17,106)	$ 68,733

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, no cost collars and applicable foreign currency forward contracts with seventeen counterparties of which one is in a net gain position of less than $0.1 million. As of June 30, 2021, no collateral was received from the counterparties by the Company. The Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties' credit ratings declined to levels at which the counterparties were required to post collateral.

As of June 30, 2021, fifteen of the seventeen counterparties to the Company’s outstanding derivative instrument contracts (specifically the over-the-counter swaps, over-the-counter no cost collars and applicable foreign currency forward contracts) had a common credit-risk related contingency feature. In the event the Company’s credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company’s credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company’s outstanding derivative instrument contracts were in a liability position (or if the liability were larger) and/or the Company’s credit rating declined, then additional hedging collateral deposits may be required. At June 30, 2021, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was less than $0.1 million according to the Company’s internal model (discussed in Note 4 – Fair Value Measurements). At June 30, 2021, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $190.4 million according to the Company's internal model. For its over-the-counter swap agreements, no cost collars and foreign currency forward contracts, $1.7 million of hedging collateral deposits were required to be posted by the Company at June 30, 2021.

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.

Note 6 – Income Taxes

The effective tax rates for the quarters ended June 30, 2021 and June 30, 2020 were 26.0% and 24.1%, respectively. The quarter increase is primarily due to a higher effective state income tax rate as a result of the Appalachian acquisition that caused a change in the mix of earnings between state jurisdictions. The effective tax rates for the nine months ended June 30, 2021 and June 30, 2020 were 26.5% and 78.9%, respectively. The change in the tax rate is primarily the result of a valuation allowance initially established in the quarter ended March 31, 2020, discussed below.

A valuation allowance for deferred tax assets, including net operating losses and tax credits, is recognized when it is more likely than not that some or all of the benefit from the deferred tax assets will not be realized. The Company continually assesses the realizability of its deferred tax assets, including factors such as future taxable income, reversal of existing temporary differences, and tax planning strategies. The Company considers both positive and negative evidence related to the likelihood of the realization of the deferred tax assets. As of March 31, 2020, the Company recorded a valuation allowance against certain state deferred tax assets in the amount of $56.8 million based on its conclusion, considering all available objective evidence and the Company's history of subsidiary state tax losses, that it was more likely than not that the deferred tax assets would not be realized. The valuation allowance increased to $64.5 million as of June 30, 2021 as a result of certain state net operating loss and tax credit activity. Changes in judgment regarding future realization of these deferred tax assets may result in a reversal of all or a portion of the valuation allowance. The Company will continue to re-assess this position each quarter.

Note 7 – Capitalization

Summary of Changes in Common Stock Equity

	Common Stock		Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
	Shares	Amount			
	(Thousands, except per share amounts)				
Balance at April 1, 2021	91,164	$ 91,164	$ 1,009,075	$ 1,100,718	$ (101,988)
Net Income Available for Common Stock				86,475	
Dividends Declared on Common Stock ($0.455 Per Share)				(41,493)	
Other Comprehensive Loss, Net of Tax					(136,474)
Share-Based Payment Expense [1]			3,196		
Common Stock Issued Under Stock and Benefit Plans	9	9	432		
Balance at June 30, 2021	91,173	$ 91,173	$ 1,012,703	$ 1,145,700	$ (238,462)
Balance at October 1, 2020	90,955	$ 90,955	$ 1,004,158	$ 991,630	$ (114,757)
Net Income Available for Common Stock				276,685	
Dividends Declared on Common Stock ($1.345 Per Share)				(122,615)	
Other Comprehensive Loss, Net of Tax					(123,705)
Share-Based Payment Expense [1]			10,975		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	218	218	(2,430)		
Balance at June 30, 2021	91,173	$ 91,173	$ 1,012,703	$ 1,145,700	$ (238,462)

	Common Stock Shares	Common Stock Amount	Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
	(Thousands, except per share amounts)				
Balance at April 1, 2020	86,562	$ 86,562	$ 835,444	$ 1,176,870	$ (18,917)
Net Income Available for Common Stock				41,250	
Dividends Declared on Common Stock ($0.445 Per Share)				(40,470)	
Other Comprehensive Loss, Net of Tax					(22,877)
Share-Based Payment Expense [(1)]			1,699		
Common Stock Issued from Sale of Common Stock	4,370	4,370	161,488		
Common Stock Issued Under Stock and Benefit Plans	12	12	426		
Balance at June 30, 2020	90,944	$ 90,944	$ 999,057	$ 1,177,650	$ (41,794)
Balance at October 1, 2019	86,315	$ 86,315	$ 832,264	$ 1,272,601	$ (52,155)
Net Income Available for Common Stock				21,773	
Dividends Declared on Common Stock ($1.315 Per Share)				(115,774)	
Cumulative Effect of Adoption of Authoritative Guidance for Hedging				(950)	
Other Comprehensive Income, Net of Tax					10,361
Share-Based Payment Expense [(1)]			8,403		
Common Stock Issued from Sale of Common Stock	4,370	4,370	161,488		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	259	259	(3,098)		
Balance at June 30, 2020	90,944	$ 90,944	$ 999,057	$ 1,177,650	$ (41,794)

(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 nine months ended June 30, 2021, the Company issued 105,307 original issue shares of common stock for restricted stock units that vested and 165,161 original issue shares of common stock for performance shares that vested. The Company also issued 30,520 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, including the reinvestment of dividends for certain non-employee directors who elected to defer their shares pursuant to the dividend reinvestment feature of the Company's Non-Employee Directors Deferred Compensation Plan during the nine months ended June 30, 2021. Holders of stock-based compensation awards will often tender shares of common stock to the Company for payment of applicable withholding taxes. During the nine months ended June 30, 2021, 82,983 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

Current Portion of Long-Term Debt. None of the Company's long-term debt as of June 30, 2021 and September 30, 2020 had a maturity date within the following twelve-month period.

Long-Term Debt. On February 24, 2021, the Company issued $500.0 million of 2.95% notes due March 1, 2031. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $495.3 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. Additionally, the interest rate payable on the notes will be subject to adjustment from time to time, with a maximum adjustment of 2.00%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes below investment grade (or if the credit rating assigned to the notes is subsequently upgraded). The proceeds of this debt issuance were used for general corporate purposes, including the redemption of $500.0 million of 4.90% notes on March 11, 2021 that were scheduled to mature in December 2021. The Company redeemed those notes for $515.7 million, plus accrued interest. The early redemption premium of $15.7 million was recorded to Interest Expense on Long-Term Debt on the Consolidated Income Statement during the quarter ended March 31, 2021.

Short-Term Borrowings. On February 3, 2021, the Company amended its existing 364-day credit facility agreement. The amendment extends the maturity date of the facility from May 3, 2021 to December 30, 2022, and increases the commitment provided under the facility from $200.0 million to $250.0 million of unsecured committed revolving credit access. The Company entered into the amendment with a syndicate of twelve banks, all of which are also lenders under the Company's existing $750.0 million multi-year credit facility.

Note 8 – Commitments and Contingencies

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

At June 30, 2021, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately $3.0 million, which includes a $0.3 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. Active remedial work at the site has been completed and restoration is currently underway. The Company's liability for such clean-up costs has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at June 30, 2021. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 1 year 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. Shortly thereafter, 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 in January of 2017). The United States Court of Appeals for the Second Circuit (the “Second Circuit Court of Appeals”) held in the Company’s favor in its appeal of this decision, vacating the NYDEC denial and remanding to the NYDEC. The NYDEC subsequently issued a second denial, which the Company has appealed to the Second Circuit Court of Appeals. The court has held this appeal in abeyance pending the outcome of the FERC waiver appeal, described below. While the Company’s initial appeal was pending before the Second Circuit Court of Appeals, 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. FERC denied rehearing requests associated with its Order and FERC's decisions were appealed. Recently, the Second Circuit Court of Appeals issued an order upholding the FERC waiver orders. In addition, in the Company's state court litigation challenging the NYDEC's actions with regard to various state permits, the New York State Supreme Court issued a decision finding these permits to be preempted. The Company remains committed to the project.

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 9 – Business Segment Information

The Company reports financial results for four segments: Exploration and Production, Pipeline and Storage, Gathering and Utility. 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 2020 Form 10-K, the Company evaluates segment performance based on income before discontinued operations (when applicable). When this is 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 2020 Form 10-K. A listing of segment assets at June 30, 2021 and September 30, 2020 is shown in the tables below.

Quarter Ended June 30, 2021 (Thousands)	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$209,535	$57,258	$588	$126,934	$394,315	$(1)	$83	$394,397
Intersegment Revenues	$—	$26,805	$48,068	$74	$74,947	$2	$(74,949)	$—
Segment Profit: Net Income (Loss)	$39,015	$21,948	$20,427	$4,841	$86,231	$1,039	$(795)	$86,475

Nine Months Ended June 30, 2021 (Thousands)	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$621,116	$175,881	$1,610	$586,618	$1,385,225	$1,174	$272	$1,386,671
Intersegment Revenues	$—	$82,651	$144,317	$271	$227,239	$22	$(227,261)	$—
Segment Profit: Net Income	$46,213	$71,060	$61,677	$59,922	$238,872	$37,617	$196	$276,685

(Thousands)	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Segment Assets:								
At June 30, 2021	$2,068,003	$2,280,993	$840,635	$2,119,835	$7,309,466	$3,971	$(104,762)	$7,208,675
At September 30, 2020	$1,979,028	$2,204,971	$945,199	$2,067,852	$7,197,050	$113,571	$(345,686)	$6,964,935

Quarter Ended June 30, 2020 (Thousands)	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$131,228	$51,020	$—	$124,390	$306,638	$16,286	$95	$323,019
Intersegment Revenues	$—	$26,793	$33,299	$2,647	$62,739	$341	$(63,080)	$—
Segment Profit: Net Income (Loss)	$(6,434)	$22,623	$15,239	$6,254	$37,682	$(9)	$3,577	$41,250

Nine Months Ended June 30, 2020 (Thousands)	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$452,728	$151,908	$—	$569,856	$1,174,492	$83,445	$364	$1,258,301
Intersegment Revenues	$—	$77,370	$103,355	$8,499	$189,224	$598	$(189,822)	$—
Segment Profit: Net Income (Loss)	$(157,733)	$62,815	$51,081	$64,335	$20,498	$1,532	$(257)	$21,773

Note 10 – Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

Three Months Ended June 30,	Retirement Plan 2021	Retirement Plan 2020	Other Post-Retirement Benefits 2021	Other Post-Retirement Benefits 2020
Service Cost	$ 2,466	$ 2,330	$ 400	$ 402
Interest Cost	5,422	7,483	2,326	3,228
Expected Return on Plan Assets	(14,537)	(15,016)	(7,241)	(7,308)
Amortization of Prior Service Cost (Credit)	158	182	(107)	(107)
Amortization of Losses	9,203	9,846	212	134
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	2,772	604	6,639	6,036
Net Periodic Benefit Cost	$ 5,484	$ 5,429	$ 2,229	$ 2,385

Nine Months Ended June 30,	Retirement Plan 2021	Retirement Plan 2020	Other Post-Retirement Benefits 2021	Other Post-Retirement Benefits 2020
Service Cost	$ 7,399	$ 6,989	$ 1,202	$ 1,206
Interest Cost	16,265	22,448	6,977	9,685
Expected Return on Plan Assets	(43,611)	(45,048)	(21,723)	(21,924)
Amortization of Prior Service Cost (Credit)	473	547	(321)	(322)
Amortization of Losses	27,610	29,538	636	401
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	14,194	7,651	22,942	21,131
Net Periodic Benefit Cost	$ 22,330	$ 22,125	$ 9,713	$ 10,177

(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.

The components of net periodic benefit cost other than service cost are presented in Other Income (Deductions) on the Consolidated Statements of Income.

Employer Contributions. During the nine months ended June 30, 2021, the Company contributed $18.9 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $2.7 million to its VEBA trusts for its other post-retirement benefits. In the remainder of 2021, the Company expects to contribute approximately $1.1 million to the Retirement Plan. In the remainder of 2021, the Company expects to contribute approximately $0.2 million to its VEBA trusts.

Note 11 – 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%. The order also directed the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018.

In New York, on March 13, 2020, in response to the COVID-19 pandemic, the Company agreed to NYPSC Staff's request that the Company suspend service terminations and disconnections. Thereafter, on June 17, 2020, New York enacted a law that prohibits utilities from terminating or disconnecting services to any residential customer for non-payment for the duration of the state disaster emergency. While that legislation expired on March 31, 2021, new legislation was enacted in May

2021 that prohibits utility terminations for non-payment for residential and small commercial customers who experienced a change in financial circumstances due to the COVID-19 state of emergency, with such prohibition running for a period of one hundred eighty days after either the New York State COVID-19 state of emergency is lifted or expires or December 31, 2021, whichever is earlier. On June 24, 2021, the New York State COVID-19 state of emergency expired. Updated guidance issued by the NYPSC on July 6, 2021 confirmed that qualified customers are protected from termination through December 21, 2021 and are eligible for a deferred payment agreement without the requirement of a down payment, late fees, penalties or interest on arrears incurred during the COVID-19 state of emergency. It is uncertain at this point as to whether there would be any regulatory relief for utilities with regard to an increase in costs associated with the COVID-19 pandemic, but it is one of many issues currently being considered in a generic NYPSC proceeding entitled “Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service” (Case No. 20-M-0266). Correspondence from NYPSC Staff has recommended that utilities rely on existing avenues of relief for these costs, and has identified additional, more stringent requirements that must be met to achieve relief.

Pennsylvania Jurisdiction

Distribution Corporation’s current delivery rates in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007. The rate settlement does not specify any requirement to file a future rate case.

On July 22, 2021, Distribution Corporation filed a supplement to its current Pennsylvania tariff proposing to reduce base rates effective October 1, 2021 by $7.7 million in order to stop collecting other post-employment benefit (“OPEB”) expenses from customers at this time, to begin to refund to customers over-collected OPEB expenses in the amount of $50.0 million, and to make certain other adjustments to further reduce Distribution Corporation’s regulatory liability associated with OPEB expenses. The refund would be funded entirely by grantor trust assets held by the Company, most of which are included in a fixed income mutual fund that is a component of Other Investments on the Company’s Consolidated Balance Sheet. With the elimination of OPEB expenses in base rates, Distribution Corporation would no longer fund the grantor trust or its VEBA trusts in its Pennsylvania jurisdiction. The proposals in the supplement filed by Distribution Corporation are subject to change and require PaPUC approval.

On March 26, 2020, the PaPUC ratified an Emergency Order that established a Service Termination Moratorium intended to continue during the pendency of Governor Wolf’s March 6, 2020 Proclamation of Disaster Emergency associated with the COVID-19 pandemic. On May 13, 2020, the Company (and other Pennsylvania local distribution companies) received a Secretarial Letter from the PaPUC regarding COVID-19 pandemic cost tracking and regulatory assets. The Secretarial Letter directs utilities to track “extraordinary, nonrecurring incremental COVID-19 related expenses” so the Commission can understand the impact of these expenses on the utilities’ finances. It also authorizes the creation of a utility regulatory asset, but only for incremental uncollectible expenses incurred above those embedded in rates (and incurred since the issuance of the Emergency Order). On October 8, 2020, the Commission issued an order ending the moratorium effective November 9, 2020, imposing a list of enhanced customer protections that expired on March 31, 2021. On March 11, 2021, the Commission adopted an order lifting the utility service termination moratorium effective April 1, 2021, and authorizing utilities to return to the regular collections process with certain modifications to customer payment arrangements. The October and March orders expanded the aforementioned potential utility regulatory asset to include all incremental COVID-19 related expenses incurred above those embedded in rates resulting from directives contained in the orders. The Company continues to monitor this item for potential deferral opportunity.

FERC Jurisdiction

Supply Corporation’s rate settlement, approved June 1, 2020, provides that no party may make a rate filing for new rates to be effective before February 1, 2024, except that Supply Corporation may file an NGA general Section 4 rate case to change rates if the corporate federal income tax rate is increased. If no case has been filed, Supply Corporation must file for rates to be effective February 1, 2025. Supply has no rate case currently on file.

Empire’s 2019 rate settlement provides that Empire must make a rate case filing no later than May 1, 2025.

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 and distribution 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 shales. 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 the eastern United States and Canada. 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 customers in the Appalachian basin. The Company also develops and produces oil reserves, primarily in California. The Company reports financial results for four business segments. For a discussion of the Company's earnings, refer to the Results of Operations section below.

The Company is closely monitoring and responding to developments related to the novel coronavirus (COVID-19) and is taking steps to limit operational impacts and the potential exposure for our workforce and customers. Refer to Risk Factors in Item 1A of this Form 10-Q as well as Part I, Item 1A, Risk Factors, under Operational Risks in the Company's 2020 Form 10-K for a more complete discussion of the risks to the Company associated with the COVID-19 pandemic.

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, which allows for the transportation of 205,000 Dth per day of additional shale supplies from interconnections in Tioga County, Pennsylvania, to the TC Energy pipeline, and the Tennessee Gas Pipeline L.L.C. (TGP) 200 Line, was placed in-service during the fourth quarter of fiscal 2020. Another project on Supply Corporation's system, referred to as the FM100 Project, will upgrade a 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, Pennsylvania to the Transcontinental Gas Pipe Line Company, LLC system at Leidy, Pennsylvania. Construction activities for the FM100 Project are fully in progress. The FM100 Project has a target in-service date of late calendar 2021 and a preliminary cost estimate of approximately $280 million. This project is discussed in more detail in the Capital Resources and Liquidity section that follows.

In advance of the expected late calendar 2021 online date for Seneca's 330,000 Dth per day of incremental capacity on the Leidy South Project, which is the companion project to the Company's FM100 Project, the Company's Exploration and Production segment added a second horizontal drilling rig in the Appalachian region in January 2021. Production from the first pad that will be drilled in connection with this additional activity is expected in early fiscal 2022, with this incremental production reaching Transco Zone 6 markets during the winter heating season.

From a legislative perspective, in July 2019, New York State enacted legislation known as the Climate Leadership & Community Protection Act (CLCPA). This climate legislation mandates reducing greenhouse gas emissions by 40% from 1990 levels by 2030, and by 85% from 1990 levels by 2050, with the remaining emission reduction achieved by controlled offsets. The legislation also requires electric generators to meet 70% of demand with renewable energy by 2030 and 100% with zero emissions generation by 2040. The CLCPA established a climate action council and a series of advisory panels and working groups to study how the state will achieve the aggressive emission reduction targets. Thus far, the only regulations promulgated in connection with the CLCPA are greenhouse gas limits established by the NYDEC on December 30, 2020. For further discussion of the CLCPA, refer to the Environmental Matters section below.

The Company uses the full cost method of accounting for determining the book value of its oil and natural gas properties in the Exploration and Production segment and that book value is subject to a quarterly ceiling test. This is discussed in more detail in the Critical Accounting Estimates section that follows. In addition to the significant non-cash impairment charges under the ceiling test that the Company recorded during fiscal 2020, the Company recorded a non-cash impairment charge under the ceiling test for the nine months ended June 30, 2021 of $76.2 million ($55.2 million after-tax), which was recorded during the quarter ended December 31, 2020. Please refer to the Critical Accounting Estimates section below for a sensitivity analysis concerning commodity price changes.

On December 10, 2020, the Company completed the sale of substantially all timber properties in Pennsylvania to Lyme Emporium Highlands III LLC and Lyme Allegheny Land Company II LLC for net proceeds of $104.6 million. After purchase price adjustments and transaction costs, a gain of $51.1 million was recognized on the sale of these assets ($37.0 million after-tax). Refer to Note 2 – Asset Acquisitions and Divestitures for additional information concerning this sale.

From a financing perspective, on February 24, 2021, the Company issued $500.0 million of 2.95% notes due March 1, 2031. The proceeds of the debt issuance were used for general corporate purposes, including the redemption of $500.0 million of 4.90% notes on March 11, 2021 that were scheduled to mature in December 2021. The Company redeemed those notes for $515.7 million, plus accrued interest.

On February 3, 2021, the Company amended its existing 364-day credit facility agreement. The amendment extends the maturity date of the facility from May 3, 2021 to December 30, 2022, and increases the commitment provided under the facility from $200.0 million to $250.0 million of unsecured committed revolving credit access. The Company entered into the amendment with a syndicate of twelve banks, all of which are also lenders under the Company's existing $750.0 million multi-year credit facility.

The sale of timber properties discussed above, combined with cash on hand, cash from operations and short-term borrowings, are expected to meet the Company's financing needs for fiscal 2021.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2020 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. The present value of future revenues is calculated using a 10% discount factor. If the book value of the oil and gas properties exceeds the ceiling, a non-cash impairment charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. At June 30, 2021, the ceiling exceeded the book value of the oil and gas properties by approximately $409.8 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended June 30, 2021, based on posted Midway Sunset prices, was $48.49 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during the twelve months ended June 30, 2021, based on the quoted Henry Hub spot price for natural gas, was $2.43 per MMBtu. (Note: Because actual pricing of the Company's producing properties vary 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 12-month average prices for the twelve months ended June 30, 2021. Actual realized pricing includes adjustments for regional market differentials, transportation fees and contractual arrangements.) The following table illustrates the sensitivity of the ceiling test calculation to commodity price changes, specifically showing the amounts the ceiling would have exceeded the book value of the Company's oil and gas properties at June 30, 2021 if natural gas prices were $0.25 per MMBtu lower than the average prices used at June 30, 2021, if crude oil prices were $5 per Bbl lower than the average prices used at June 30, 2021, and if both natural gas prices and crude oil prices were $0.25 per MMBtu and $5 per Bbl lower than the average prices used at June 30, 2021 (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 Decrease in Natural Gas Prices**	**$5.00/Bbl Decrease in Crude Oil Prices**	**$0.25/MMBtu Decrease in Natural Gas Prices and $5.00/Bbl Decrease in Crude Oil Prices**
Excess of Ceiling over Book Value under Sensitivity Analysis	$ 149.3	$ 377.4	$ 117.0

It is difficult to predict what factors could lead to future non-cash 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 2020 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $86.5 million for the quarter ended June 30, 2021 compared to earnings of $41.3 million for the quarter ended June 30, 2020. The increase in earnings of $45.2 million is primarily the result of higher earnings in the Exploration and Production segment, Gathering segment and All Other category. Lower earnings in the Utility segment and Pipeline and Storage segment, as well as a loss in the Corporate category, partially offset these increases.

The Company's earnings were $276.7 million for the nine months ended June 30, 2021 compared to earnings of $21.8 million for the nine months ended June 30, 2020. The increase in earnings of $254.9 million is primarily the result of higher earnings in the Exploration and Production segment, Gathering segment, Pipeline and Storage segment and Corporate and All Other categories. Lower earnings in the Utility segment partially offset these increases.

The Company's earnings for the nine months ended June 30, 2021 included a non-cash $76.2 million impairment charge ($55.2 million after-tax) recorded during the quarter ended December 31, 2020 for the Exploration and Production segment's oil and gas producing properties, as discussed above. The Company's earnings for the nine months ended June 30, 2021 also included a gain recognized on the sale of timber properties of $51.1 million ($37.0 million after-tax) recorded during the quarter ended December 31, 2020 in the Company's All Other category, as discussed above. The Company's earnings for the quarter and nine months ended June 30, 2020 included non-cash impairment charges of $18.2 million ($13.2 million after-tax) and $196.0 million ($142.5 million after-tax), respectively, recorded during the quarter and nine months ended June 30, 2020 for the Exploration and Production segment's oil and gas producing properties. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2021	2020	Increase (Decrease)	2021	2020	Increase (Decrease)
Exploration and Production	$ 39,015	$ (6,434)	$ 45,449	$ 46,213	$ (157,733)	$ 203,946
Pipeline and Storage	21,948	22,623	(675)	71,060	62,815	8,245
Gathering	20,427	15,239	5,188	61,677	51,081	10,596
Utility	4,841	6,254	(1,413)	59,922	64,335	(4,413)
Total Reportable Segments	86,231	37,682	48,549	238,872	20,498	218,374
All Other	1,039	(9)	1,048	37,617	1,532	36,085
Corporate	(795)	3,577	(4,372)	196	(257)	453
Total Consolidated	$ 86,475	$ 41,250	$ 45,225	$ 276,685	$ 21,773	$ 254,912

Exploration and Production

Exploration and Production Operating Revenues

(Thousands)	Three Months Ended June 30, 2021	2020	Increase (Decrease)	Nine Months Ended June 30, 2021	2020	Increase (Decrease)
Gas (after Hedging)	$ 175,378	$ 100,951	$ 74,427	$ 524,417	$ 347,327	$ 177,090
Oil (after Hedging)	33,065	29,624	3,441	93,256	102,766	(9,510)
Gas Processing Plant	732	435	297	2,056	1,838	218
Other	360	218	142	1,387	797	590
	$ 209,535	$ 131,228	$ 78,307	$ 621,116	$ 452,728	$ 168,388

Production Volumes

	Three Months Ended June 30, 2021	2020	Increase (Decrease)	Nine Months Ended June 30, 2021	2020	Increase (Decrease)
Gas Production *(MMcf)*						
Appalachia	79,314	52,043	27,271	236,429	161,965	74,464
West Coast	431	468	(37)	1,300	1,434	(134)
Total Production	79,745	52,511	27,234	237,729	163,399	74,330
Oil Production *(Mbbl)*						
Appalachia	1	—	1	2	2	—
West Coast	557	584	(27)	1,681	1,790	(109)
Total Production	558	584	(26)	1,683	1,792	(109)

Average Prices

	Three Months Ended June 30, 2021	2020	Increase (Decrease)	Nine Months Ended June 30, 2021	2020	Increase (Decrease)
Average Gas Price/Mcf						
Appalachia	$ 2.29	$ 1.45	$ 0.84	$ 2.25	$ 1.80	$ 0.45
West Coast	$ 5.36	$ 2.58	$ 2.78	$ 5.83	$ 3.98	$ 1.85
Weighted Average	$ 2.31	$ 1.46	$ 0.85	$ 2.27	$ 1.82	$ 0.45
Weighted Average After Hedging	$ 2.20	$ 1.92	$ 0.28	$ 2.21	$ 2.13	$ 0.08
Average Oil Price/Bbl						
Appalachia	$ 42.09	$ 27.50	$ 14.59	$ 43.13	$ 50.28	$ (7.15)
West Coast	$ 67.55	$ 29.13	$ 38.42	$ 56.92	$ 47.40	$ 9.52
Weighted Average	$ 67.52	$ 29.12	$ 38.40	$ 56.90	$ 47.41	$ 9.49
Weighted Average After Hedging	$ 59.22	$ 50.70	$ 8.52	$ 55.40	$ 57.35	$ (1.95)

2021 Compared with 2020

Operating revenues for the Exploration and Production segment increased $78.3 million for the quarter ended June 30, 2021 as compared with the quarter ended June 30, 2020. Gas production revenue after hedging increased $74.4 million due to the impact of a 27.2 Bcf increase in natural gas production, together with a $0.28 per Mcf increase in the weighted average price of natural gas after hedging. Natural gas production increased largely due to additional production from the Company's fourth quarter fiscal 2020 acquisition of Appalachian upstream assets from Shell coupled with new Marcellus and Utica wells in the Appalachian region. Oil production revenue after hedging increased $3.4 million due to an $8.52 per Bbl increase in the weighted average price of oil after hedging, offset by the impact of a 26 Mbbl decrease in oil production. The decrease in oil production was largely due to natural production declines.

Operating revenues for the Exploration and Production segment increased $168.4 million for the nine months ended June 30, 2021 as compared with the nine months ended June 30, 2020. Gas production revenue after hedging increased $177.1 million due to the impact of a 74.3 Bcf increase in gas production combined with a $0.08 per Mcf increase in the weighted average price of gas after hedging. The increase in gas production was largely due to additional production from the Company's fourth quarter fiscal 2020 acquisition of Appalachian upstream assets from Shell coupled with new Marcellus and Utica wells in the Appalachian region during the nine months ended June 30, 2021 as compared with the nine months ended June 30, 2020. Oil production revenue after hedging decreased $9.5 million due to a $1.95 per Bbl decrease in the weighted average price of oil after hedging, coupled with the impact of a 109 Mbbl decrease in oil production. The decrease in oil production was largely due to natural production declines.

The Exploration and Production segment's earnings for the quarter ended June 30, 2021 were $39.0 million, an increase of $45.4 million when compared with a loss of $6.4 million for the quarter ended June 30, 2020. The increase in earnings was due to a quarter ended June 30, 2020 non-cash impairment of oil and gas properties ($13.2 million), higher natural gas production ($41.4 million), higher natural gas prices after hedging ($17.4 million), higher oil prices after hedging ($3.8 million) and lower interest expense ($1.8 million). The positive earnings impact of these items was partially offset by lower oil production ($1.0 million), higher lease operating and transportation expenses ($16.2 million), higher depletion expense ($5.1 million), higher other operating expenses ($2.4 million), higher other taxes ($2.8 million) and a higher effective tax rate ($5.0 million). The decrease in interest expense can largely be attributed to lower intercompany long-term and short-term borrowings combined with lower rates. The increase in lease operating and transportation expenses was primarily the result of increased gathering and transportation costs in the Appalachian region due to increased production. The increase in depletion expense was primarily due to the net increase in production offset by a $0.15 per Mcf decrease in the depletion rate due to prior period non-cash ceiling test impairments coupled with the impact of the asset acquisition from Shell. The increase in other operating expense was largely attributed to an increase in accretion costs associated with asset retirement obligations, as well as higher personnel costs and technology-related expenses. The increase in other taxes was mainly attributed to increased impact fees in our Appalachian region due to added wells from the Shell acquisition combined with NYMEX gas price increases, shifting fees into a higher per well tier. The increase in the effective tax rate was primarily driven by a higher effective state income tax rate as a result of the Company's asset acquisition from Shell that caused a change in the mix of earnings between state jurisdictions.

The Exploration and Production segment's earnings for the nine months ended June 30, 2021 were $46.2 million, an increase of $203.9 million when compared with a loss of $157.7 million for the nine months ended June 30, 2020. The increase in earnings was primarily attributable to a decrease in impairments of oil and gas properties ($142.5 million during the nine months ended June 30, 2020 compared to $55.2 million during the nine months ended June 30, 2021), higher natural gas production ($124.8 million), higher natural gas prices after hedging ($15.1 million) and a deferred tax valuation allowance established during the quarter ended March 31, 2020 as discussed more completely in Item 1 at Note 6 — Income Taxes ($60.5 million). These increases in earnings were partially offset by lower oil production ($4.9 million), lower oil prices after hedging ($2.6 million), higher lease operating and transportation expenses ($40.0 million), higher depletion expense ($6.9 million), higher other operating expenses ($4.9 million), higher other taxes ($3.5 million) and a higher effective tax rate ($10.6 million). The increase in lease operating and transportation expenses was primarily the result of increased gathering and transportation costs in the Appalachian region due to increased production. The increase in depletion expense was primarily due to the net increase in production offset by a $0.19 per Mcf decrease in the depletion rate due to prior period non-cash ceiling test impairments coupled with the impact of the asset acquisition from Shell. The increase in other operating expense was largely attributed to an increase in accretion costs associated with asset retirement obligations, as well as higher personnel costs and technology-related expenses. The increase in other taxes was mainly attributed to increased impact fees in our Appalachian region due to added wells from the Shell acquisition combined with NYMEX gas price increases, shifting fees into a higher per well tier. The increase in the effective tax rate was primarily driven by a higher effective state income tax rate as a result of the Company's asset acquisition from Shell that caused a change in the mix of earnings between state jurisdictions. Finally, the Exploration and Production segment recognized a loss in March 2021 ($10.7 million) for its share of the premium paid by the Company to redeem $500 million of the Company’s 4.90% notes that were scheduled to mature in December 2021.

Pipeline and Storage

Pipeline and Storage Operating Revenues

(Thousands)	Three Months Ended June 30, 2021	2020	Increase (Decrease)	Nine Months Ended June 30, 2021	2020	Increase (Decrease)
Firm Transportation	$ 62,886	$ 57,346	$ 5,540	$ 191,889	$ 168,777	$ 23,112
Interruptible Transportation	221	217	4	691	692	(1)
	63,107	57,563	5,544	192,580	169,469	23,111
Firm Storage Service	20,646	19,999	647	62,351	58,942	3,409
Interruptible Storage Service	—	17	(17)	43	24	19
Other	310	234	76	3,558	843	2,715
	$ 84,063	$ 77,813	$ 6,250	$ 258,532	$ 229,278	$ 29,254

Pipeline and Storage Throughput

(MMcf)	Three Months Ended June 30, 2021	2020	Increase (Decrease)	Nine Months Ended June 30, 2021	2020	Increase (Decrease)
Firm Transportation	174,224	172,579	1,645	586,748	577,025	9,723
Interruptible Transportation	181	757	(576)	1,205	2,002	(797)
	174,405	173,336	1,069	587,953	579,027	8,926

2021 Compared with 2020

Operating revenues for the Pipeline and Storage segment increased $6.3 million for the quarter ended June 30, 2021 as compared with the quarter ended June 30, 2020. The increase in operating revenues was primarily due to an increase in transportation revenues of $5.5 million and an increase in storage revenues of $0.6 million. The increase in transportation revenues was primarily attributable to new demand charges for transportation service from the Empire North Project, which was placed into service during the fourth quarter of fiscal 2020. The increase in transportation revenues was partially offset by a modest decrease in transportation revenues from miscellaneous contract revisions. The increase in storage revenues was primarily attributable to a surcharge for Pipeline Safety and Greenhouse Gas Regulatory Costs (PS/GHG Regulatory Costs) that went into effect in November 2020 associated with Supply Corporation’s 2020 rate case settlement. The PS/GHG surcharge is also applicable to transportation revenues, but it did not have a significant impact to the increase in transportation revenues for the quarter.

Operating revenues for the Pipeline and Storage segment increased $29.3 million for the nine months ended June 30, 2021 as compared with the nine months ended June 30, 2020. The increase in operating revenues was primarily due to an increase in transportation revenues of $23.1 million, an increase in storage revenues of $3.4 million and an increase in other revenues of $2.7 million. The increase in transportation revenues was primarily due to new demand charges for transportation service from the Empire North Project being placed into service as mentioned above. Transportation revenue also increased due to an increase in Supply Corporation's transportation rates effective February 1, 2020 related to the rate case settlement mentioned above. The increase in transportation revenues was partially offset by the end of the PS/GHG surcharge that had been in effect under Supply Corporation's last rate case settlement (RP15-1310) but which ended with the effective date of Supply Corporation’s 2020 rate case settlement (February 1, 2020), and also by a decrease in transportation revenues from miscellaneous contract revisions and a decrease in revenues from short-term seasonal contracts. The increase in storage revenues was largely attributable to an increase in Supply Corporation's storage rates related to its 2020 rate case settlement. The increase in other revenues was primarily due to proceeds received during the quarter ended December 31, 2020 as a result of a contract buyout.

Transportation volume for the quarter ended June 30, 2021 increased by 1.1 Bcf from the prior year's quarter, primarily due to incremental volume from the Empire North Project, which was brought online on September 15, 2020. For the nine months ended June 30, 2021, transportation volume increased by 8.9 Bcf from the prior year's nine-month period ended June 30, 2020. The increase in transportation volume for the nine-month period primarily reflects an increase in volume from the Empire North Project, partially offset by a decrease in volume from a decline in capacity utilization by certain contract shippers. Volume fluctuations, other than those caused by the addition or termination of contracts, generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

The Pipeline and Storage segment’s earnings for the quarter ended June 30, 2021 were $21.9 million, a decrease of $0.7 million when compared with earnings of $22.6 million for the quarter ended June 30, 2020. The decrease in earnings was primarily due to an increase in operating expenses ($2.9 million), an increase in interest expense ($1.8 million) and an increase in depreciation expense ($1.0 million). The increase in operating expenses was mainly due to higher pipeline integrity costs, higher compressor and facility maintenance costs, an increase in personnel costs and higher power costs related to Empire's electric motor drive compressor station placed into service as part of the Empire North Project mentioned above. Power costs related to Empire’s electric motor drive compressor station are offset by an equal amount of revenue due to a surcharge mechanism. The increase in interest expense was primarily due to interest on additional intercompany long-term borrowings associated with the Company's June 2020 debt issuance. The increase in depreciation expense was primarily due to incremental depreciation from the Empire North Project going into service, as mentioned above. These earnings decreases were partially offset by the impact of higher operating revenues of $4.9 million, as discussed above.

The Pipeline and Storage segment’s earnings for the nine months ended June 30, 2021 were $71.1 million, an increase of $8.3 million when compared with earnings of $62.8 million for the nine months ended June 30, 2020. The increase in earnings was primarily due to the earnings impact of higher operating revenues of $23.1 million, as discussed above, combined with lower income tax expense ($0.6 million). The decrease in income tax expense was mainly due to the timing of passing back excess deferred taxes to rate payers as a result of the 2017 Tax Reform Act per the Supply Corporation 2020 rate case settlement. These earnings increases were partially offset by an increase in depreciation expense ($5.9 million), higher interest expense ($7.4 million), an increase in operating expenses ($1.3 million), as well as a decrease in other income ($1.0 million). The increase in depreciation expense was due to an increase in Supply Corporation's depreciation rates associated with its 2020 rate case settlement as well as incremental depreciation from the Empire North Project going into service, both mentioned above. The increase in interest expense was primarily due to interest on additional intercompany long-term borrowings associated with the Company's June 2020 debt issuance. The increase in operating expenses, which were primarily power costs related to Empire's electric motor drive compressor station, discussed in the previous paragraph, as well as higher personnel and technology-related costs and an increase in compressor and facility maintenance costs, were partially offset by a decrease in the reserve for preliminary project costs. The decrease in other income was mainly due to a decrease in allowance for funds used during construction (equity component) as a result of the Empire North Project being placed in service during the fourth quarter of fiscal 2020, partially offset by non-service pension and post-retirement income in the current nine-month period compared to non-service pension and post-retirement benefit costs in the nine months ended June 30, 2020.

Gathering

Gathering Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2021	2020	Increase (Decrease)	2021	2020	Increase (Decrease)
Gathering Revenues	$ 48,656	$ 33,299	$ 15,357	$ 145,927	$ 103,355	$ 42,572

Gathering Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2021	2020	Increase (Decrease)	2021	2020	Increase (Decrease)
Gathered Volume - (MMcf)	91,817	61,338	30,479	275,283	190,864	84,419

2021 Compared with 2020

Operating revenues for the Gathering segment increased $15.4 million for the quarter ended June 30, 2021 as compared with the quarter ended June 30, 2020, which was driven primarily by a 30.5 Bcf increase in gathered volume. The July 31, 2020 acquisition of midstream gathering assets from Shell was the primary driver of this increase. The Tioga gathering system, which includes the Shell assets and legacy Covington gathering assets, recorded an 18.7 Bcf increase in gathered volume for the quarter ended June 30, 2021. Other contributors to the increase included the Clermont, Wellsboro and Trout Run gathering systems, which recorded increases of 3.9 Bcf, 3.7 Bcf and 4.2 Bcf, respectively. The increase in gathered volume can be attributed primarily to the increase in Seneca's gross natural gas production in the Appalachian region, as discussed above.

Operating revenues for the Gathering segment increased $42.6 million for the nine months ended June 30, 2021 as compared with the nine months ended June 30, 2020, which was driven primarily by an 84.4 Bcf increase in gathered volume. This increase was primarily due to the Tioga gathering system, which recorded a 58.1 Bcf increase in gathered volume due to the acquisition of midstream gathering assets from Shell. Other contributors to the increase included the Clermont, Wellsboro and Trout Run gathering systems, which recorded increases of 11.8 Bcf, 8.1 Bcf and 6.4 Bcf, respectively. The increase in gathered volume can be attributed to the net increase in Seneca's natural gas production, as discussed above.

The Gathering segment’s earnings for the quarter ended June 30, 2021 were $20.4 million, an increase of $5.2 million when compared with earnings of $15.2 million for the quarter ended June 30, 2020. The increase in earnings was mainly due to higher gathering revenues ($12.1 million) driven by the increase in gathered volume, as discussed above. This earnings increase was partially offset by higher operating expenses ($2.6 million), higher depreciation expense ($2.3 million) and higher interest expense ($1.4 million). The increase in operating expenses was largely due to higher lease compression expense associated with the Tioga gathering system. The increase in depreciation expense was largely due to higher plant balances associated with the Tioga gathering system. The increase in interest expense was primarily driven by additional intercompany long-term borrowings from the Company's long-term debt issuances in June 2020 and February 2021. Earnings also decreased due to higher income tax expense ($0.7 million).

The Gathering segment’s earnings for the nine months ended June 30, 2021 were $61.7 million, an increase of $10.6 million when compared with earnings of $51.1 million for the nine months ended June 30, 2020. The increase in earnings was mainly due to higher gathering revenues ($33.6 million) driven by the increase in gathered volume, as discussed above. Additionally, the Gathering segment's earnings were negatively impacted ($3.8 million) as a result of the Gathering segment's recognition of an income tax benefit that was recorded during the quarter ended March 31, 2020 as an offset to the valuation allowance established in the Exploration and Production segment. This offset is a result of the Gathering and Exploration and Production segments’ subsidiaries filing a combined state tax return. Earnings also decreased due to higher operating expenses ($6.5 million), higher depreciation expense ($6.7 million) and higher interest expense ($4.5 million). The increase in operating expenses was largely due to higher lease compression expense associated with the Tioga gathering system. The increase in depreciation expense was largely due to higher plant balances associated with the Tioga gathering system. The increase in interest expense was primarily driven by additional intercompany long-term borrowings from the Company's long-term debt issuances in June 2020 and February 2021. Finally, the Gathering segment recognized a loss in March 2021 ($0.7 million) for its share of the premium paid by the Company to redeem $500 million of the Company's 4.90% notes that were scheduled to mature in December 2021.

Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2021	2020	Increase (Decrease)	2021	2020	Increase (Decrease)
Retail Sales Revenues:						
Residential	$ 94,611	$ 93,329	$ 1,282	$ 439,853	$ 426,877	$ 12,976
Commercial	10,966	10,577	389	57,369	56,450	919
Industrial	497	616	(119)	2,798	3,045	(247)
	106,074	104,522	1,552	500,020	486,372	13,648
Transportation	21,371	23,176	(1,805)	93,437	99,492	(6,055)
Other	(437)	(661)	224	(6,568)	(7,509)	941
	$ 127,008	$ 127,037	$ (29)	$ 586,889	$ 578,355	$ 8,534

Utility Throughput

(MMcf)	Three Months Ended June 30, 2021	Three Months Ended June 30, 2020	Increase (Decrease)	Nine Months Ended June 30, 2021	Nine Months Ended June 30, 2020	Increase (Decrease)
Retail Sales:						
Residential	9,776	11,312	(1,536)	57,241	56,943	298
Commercial	1,369	1,450	(81)	8,206	8,295	(89)
Industrial	65	106	(41)	441	506	(65)
	11,210	12,868	(1,658)	65,888	65,744	144
Transportation	13,298	13,520	(222)	55,815	59,233	(3,418)
	24,508	26,388	(1,880)	121,703	124,977	(3,274)

Degree Days

Three Months Ended June 30,	Normal	2021	2020	Percent Colder (Warmer) Than Normal[1]	Percent Colder (Warmer) Than Prior Year[1]
Buffalo, NY	912	794	1,032	(12.9) %	(23.1)%
Erie, PA	871	741	920	(14.9) %	(19.5)%
Nine Months Ended June 30,					
Buffalo, NY	6,455	5,693	6,002	(11.8) %	(5.1)%
Erie, PA	6,023	5,188	5,381	(13.9) %	(3.6)%

(1) Percents compare actual 2021 degree days to normal degree days and actual 2021 degree days to actual 2020 degree days.

2021 Compared with 2020

Operating revenues for the Utility segment remained relatively flat for the quarter ended June 30, 2021 as compared with the quarter ended June 30, 2020. Transportation revenues decreased $1.8 million due to a 0.2 Bcf decrease in transportation throughput and the migration of residential transportation customers to retail. However, this decrease was offset by a $1.6 million increase in retail gas sales revenue, which was largely attributable to an increase in the cost of gas sold (per Mcf), and a $0.2 million increase in other revenues.

Operating revenues for the Utility segment increased $8.5 million for the nine months ended June 30, 2021 as compared with the nine months ended June 30, 2020. The increase largely resulted from a $13.6 million increase in retail gas sales revenue and a $0.9 million increase in other revenues. The increase in retail gas sales revenue was largely a result of the migration of residential transportation customers to retail, in addition to a modest increase in the cost of gas sold (per Mcf). The increase in other revenues was largely due to a smaller estimated refund provision recorded during the nine months ended June 30, 2021 related to the current income tax benefits resulting from the 2017 Tax Reform Act ($1.9 million) partially offset by lower late payment charges billed to customers ($1.0 million). These increases were partially offset by a $6.1 million decrease in transportation revenues. The decrease in transportation revenues was primarily due to a 3.4 Bcf decrease in transportation throughput due to the migration of residential transportation customers to retail and warmer weather.

The Utility segment’s earnings for the quarter ended June 30, 2021 were $4.8 million, a decrease of $1.5 million when compared with earnings of $6.3 million for the quarter ended June 30, 2020. The decrease in earnings was largely attributable to lower usage and weather on customer margins ($0.8 million), lower other income ($0.6 million) due to a smaller unrealized gain on investments, and higher depreciation expense ($0.5 million) largely due to higher plant balances. These decreases were slightly offset by a lower effective tax rate ($0.5 million) and the impact of a system modernization tracker in New York ($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 June 30, 2021, the WNC increased earnings by approximately $1.3 million, as the weather was warmer than normal. For the quarter ended June 30, 2020, the WNC decreased earnings by approximately $0.1 million, as the weather was colder than normal.

The Utility segment's earnings for the nine months ended June 30, 2021 were $59.9 million, a decrease of $4.4 million when compared with earnings of $64.3 million for the nine months ended June 30, 2020. The decrease in earnings was largely attributable to higher operating expenses ($3.2 million), which were primarily a result of higher personnel costs and an increase to the allowance for uncollectible accounts, higher depreciation expense ($1.2 million) largely due to higher plant balances, the impact of regulatory true-up adjustments ($1.2 million), higher income tax expense ($0.7 million), the impacts of lower usage and weather on customer margins ($0.5 million), and lower other income ($0.4 million) due to the change in unrealized gains and losses on investments. The increase to the allowance for uncollectible accounts is related to the COVID-19 pandemic as the Company recorded incremental expense due to the potential for customer non-payment, given the current economic environment. These decreases were partially offset by the positive earnings impact related to the system modernization tracker ($2.9 million).

For the nine months ended June 30, 2021, the WNC increased earnings by approximately $4.5 million, as the weather was warmer than normal. For the nine months ended June 30, 2020, the WNC increased earnings by approximately $3.5 million, as the weather was warmer than normal.

Corporate and All Other

2021 Compared with 2020

Corporate and All Other operations had earnings of $0.2 million for the quarter ended June 30, 2021, which was $3.4 million lower than earnings of $3.6 million for the quarter ended June 30, 2020. The decrease in earnings was primarily attributable to the changes in unrealized gains on investments in equity securities. During the quarter ended June 30, 2021, the Company recorded unrealized gains of $0.8 million. During the quarter ended June 30, 2020, the Company recorded unrealized gains of $4.5 million.

For the nine months ended June 30, 2021, Corporate and All Other operations had earnings of $37.8 million, an increase of $36.5 million when compared with earnings of $1.3 million for the nine months ended June 30, 2020. The increase in earnings was primarily attributable to the gain recognized on the sale of timber properties by Seneca's Northeast Division for $51.1 million ($37.0 million after-tax). The increase can also be attributed to unrealized gains on investments in equity securities of $0.5 million during the nine months ended June 30, 2021 compared to unrealized losses on investments in equity securities of $0.6 million during the nine months ended June 30, 2020. Offsetting these positive factors, the remaining $1.6 million variation largely represents lower earnings from the Company's energy marketing operations, which sold its commercial and industrial contracts and certain other assets in August 2020, and its timber operations, which ended with the sale of substantially all timber properties in December 2020. Please refer to Note 2 – Asset Acquisitions and Divestitures in Item 1 for further discussion of the sale of timber properties.

Other Income (Deductions)

Net other deductions on the Consolidated Statement of Income were $2.0 million for the quarter ended June 30, 2021, compared to other income of $2.5 million for the quarter ended June 30, 2020. This change is primarily attributable to changes in realized and unrealized gains and losses on investments in equity securities. During the quarter ended June 30, 2021, the Company recorded pre-tax realized gains of $0.7 million and pre-tax unrealized gains of $1.1 million. During the quarter ended June 30, 2020, the Company recorded pre-tax unrealized gains of $6.6 million.

For the nine months ended June 30, 2021, net other deductions decreased $2.9 million as compared to the nine months ended June 30, 2020. This change is primarily attributable to changes in realized and unrealized gains and losses on investments in equity securities. During the nine months ended June 30, 2021, the Company recorded pre-tax realized gains of $4.0 million and pre-tax unrealized gains of $0.6 million. During the nine months ended June 30, 2020, the Company recorded pre-tax realized gains of $1.8 million and pre-tax unrealized losses of $0.4 million. Also contributing to the change for the nine months ended June 30, 2021 was an increase in the cash surrender value of life insurance of $1.2 million and a decrease in the pension and post-retirement non-service benefit cost expense of $1.3 million. This was partially offset by a decrease in allowance for funds used during construction (equity component) of $2.2 million.

Interest Expense on Long-Term Debt

Interest expense on long-term debt on the Consolidated Statement of Income increased $3.1 million for the quarter ended June 30, 2021 as compared to the quarter ended June 30, 2020 due largely to the higher average long-term debt balance stemming from the issuance of $500.0 million of 5.50% notes in June 2020. This increase was partially offset by a lower weighted average interest rate on long-term debt, stemming from the Company's issuance of $500.0 million of 2.95% notes in February 2021, which replaced $500.0 million of 4.90% notes that were retired in March 2021. For the nine months ended June 30, 2021, interest expense on long-term debt increased $33.4 million as compared with the nine months ended June 30, 2020. The Company redeemed $500.0 million of 4.90% notes in March 2021 and paid an early redemption premium of $15.7 million that was recorded as interest expense on long-term debt. The remaining increase is due largely to the higher average long-term debt balance previously discussed.

CAPITAL RESOURCES AND LIQUIDITY

The Company’s primary sources of cash during the nine-month period ended June 30, 2021 consisted of cash provided by operating activities, net proceeds from the sale of timber properties and net proceeds from the issuance of long-term debt. The Company's primary sources of cash during the nine-month period ended June 30, 2020 consisted of cash provided by operating activities and net proceeds from long-term borrowings and issuance of common stock.

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, gains and losses associated with investing and financing activities, and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, deferred income taxes and stock-based compensation.

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

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

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

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil as well as changes in production. The Company uses various derivative financial instruments, including price swap agreements and no cost collars, in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $671.8 million for the nine months ended June 30, 2021, an increase of $47.9 million compared with $623.9 million provided by operating activities for the nine months ended June 30, 2020. The increase in cash provided by operating activities primarily reflects higher cash provided by operating activities in the Pipeline and Storage segment, the Exploration and Production segment, and the Gathering segment, slightly offset by lower cash provided by operating activities in the Utility segment. The increase in the Pipeline and Storage segment was primarily due to higher cash receipts from transportation and storage service, which largely reflects an increase in Supply Corporation's transportation and storage rates effective February 1, 2020 and an increase in demand charges for transportation services from the Empire North Project that was placed in service during September 2020 and the Line N to Monaca Project that was placed in service in November 2019. The increase in the Exploration and Production segment and the Gathering segment was primarily due to higher cash receipts from natural gas production and gathering services in the Appalachian region, largely stemming from the July 31, 2020 acquisition of upstream assets and midstream gathering assets from Shell. The decrease in the Utility segment is primarily due to the timing of gas cost recovery and the timing of receivable collections.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets totaled $509.7 million during the nine months ended June 30, 2021 and $528.0 million during the nine months ended June 30, 2020. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets						
Nine Months Ended June 30, (Millions)		2021		2020		Increase (Decrease)
Exploration and Production:						
Capital Expenditures	$	263.8 [1]	$	295.0 [2]	$	(31.2)
Pipeline and Storage:						
Capital Expenditures		155.5 [1]		124.1 [2]		31.4
Gathering:						
Capital Expenditures		25.6 [1]		46.2 [2]		(20.6)
Utility:						
Capital Expenditures		66.7 [1]		62.2 [2]		4.5
All Other:						
Capital Expenditures		0.2		0.5		(0.3)
Eliminations		(2.1)		—		(2.1)
	$	509.7	$	528.0	$	(18.3)

(1) At June 30, 2021, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $49.7 million, $25.8 million, $0.9 million and $5.1 million, respectively, of non-cash capital expenditures. At September 30, 2020, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $45.8 million, $17.3 million, $13.5 million and $10.7 million, respectively, of non-cash capital expenditures.

(2) At June 30, 2020, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $26.5 million, $16.4 million, $6.5 million and $8.7 million, respectively, of non-cash capital expenditures. At September 30, 2019, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $38.0 million, $23.8 million, $6.6 million and $12.7 million, respectively, of non-cash capital expenditures.

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2021 were primarily well drilling and completion expenditures and included approximately $255.8 million for the Appalachian region (including $79.8 million in the Marcellus Shale area and $155.6 million in the Utica Shale area) and $8.0 million for the West Coast region. These amounts included approximately $68.5 million spent to develop proved undeveloped reserves.

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2020 were primarily well drilling and completion expenditures and included approximately $270.1 million for the Appalachian region (including $93.8 million in the Marcellus Shale area and $166.9 million in the Utica Shale area) and $24.9 million for the West Coast region. These amounts included approximately $186.9 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2021 were primarily for expenditures related to Supply Corporation's FM100 Project ($115.4 million), which is discussed below. In addition, the Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2021 included additions, improvements and replacements to this segment's transmission and gas storage systems. The Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2020 were primarily for expenditures related to the Empire North Project ($59.5 million), and also included expenditures related to Supply Corporation's Line N to Monaca Project ($3.8 million) and Supply Corporation's FM100 Project ($2.9 million). In addition, the Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2020 included additions, improvements and replacements to this segment’s transmission and gas storage systems.

In light of the continuing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia, specifically in the Marcellus and Utica Shale producing areas, Supply Corporation and Empire have completed and continue to pursue 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 has developed its FM100 Project, which will upgrade a 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 ("Lease") and become part of a Transco expansion project ("Leidy South") that will create incremental transportation capacity to Transco Zone 6 markets. Seneca is an anchor shipper on Leidy South, which provides it with an outlet to premium markets from both its Eastern and Western development areas. FERC issued the Section 7(c) certificate on July 17, 2020 and Supply Corporation accepted it on August 14, 2020. FERC issued a Notice to Proceed on February 22, 2021, and the Lease was fully executed on that date. Construction activities are fully in progress. The FM100 Project has a target in-service date of late calendar 2021 and a preliminary cost estimate of approximately $280 million. As of June 30, 2021, approximately $122.5 million has been capitalized as Construction Work in Progress for this project.

Supply Corporation and Empire have developed a project which would move significant prospective Marcellus production from Seneca's Western Development Area at Clermont to an Empire interconnection with the TC Energy 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. Shortly thereafter, 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 in January of 2017). The United States Court of Appeals for the Second Circuit (the “Second Circuit Court of Appeals”) held in the Company’s favor in its appeal of this decision, vacating the NYDEC denial and remanding to the NYDEC. The NYDEC subsequently issued a second denial, which the Company has appealed to the Second Circuit Court of Appeals. The court has held this appeal in abeyance pending the outcome of the FERC waiver appeal, described below. While the Company’s initial appeal was pending before the Second Circuit Court of Appeals, 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. FERC denied rehearing requests associated with its Order, and FERC's decisions were appealed. Recently, the Second Circuit Court of Appeals issued an order upholding the FERC waiver orders. In addition, in the Company's state court litigation challenging the NYDEC's actions with regard to various state permits, the New York State Supreme Court issued a decision finding these permits to be preempted. The Company remains committed to the project. The Company will update the $500 million preliminary cost estimate and expected in-service date for the project when there is further clarity on the pending legal and regulatory actions. As of June 30, 2021, approximately $55.7 million has been spent on the Northern Access project, including $24.1 million that has been spent to study the project, for which no reserve has been established. The remaining $31.6 million spent on the project is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2021.

Gathering

The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2021 included expenditures related to the continued expansion of Midstream Company's Clermont and Wellsboro gathering systems, as discussed below. Midstream Company spent $15.1 million and $3.7 million, respectively, during the nine months ended June 30, 2021 on the development of the Clermont and Wellsboro gathering systems. These expenditures were largely attributable to new Clermont gathering pipelines, as well as the continued development of centralized station facilities, including increased compression horsepower at the Clermont and Wellsboro gathering systems and additional dehydration on the Clermont gathering system.

The majority of the Gathering segment capital expenditures for the nine months ended June 30, 2020 were for the continued expansion of Midstream Company's Trout Run, Clermont and Wellsboro gathering systems. Midstream Company spent $24.5 million, $11.9 million and $9.5 million, respectively, during the nine months ended June 30, 2020 on the development of the Trout Run, Clermont and Wellsboro gathering systems. These expenditures were largely attributable to new gathering pipelines and the continued development of centralized station facilities, including increased compression horsepower and a new metering and regulation station at the Trout Run gathering system, the first phase of compression at the Wellsboro gathering system, and additional dehydration at the Clermont 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 three compressor stations and 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.

NFG Midstream Wellsboro, LLC, a wholly owned subsidiary of Midstream Company, continues to develop its Wellsboro gathering system in Tioga County, Pennsylvania. The current system consists of one compressor station and backbone and in-field gathering pipelines.

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 three compressor stations and backbone and in-field gathering pipelines.

Utility

The majority of the Utility segment capital expenditures for the nine months ended June 30, 2021 and June 30, 2020 were made for main and service line improvements and replacements that enhance the reliability and safety of the system and reduce emissions. Expenditures were also made for main extensions.

Other Investing Activities

On December 10, 2020, the Company completed the sale of substantially all timber properties in Pennsylvania to Lyme Emporium Highlands III LLC and Lyme Allegheny Land Company II LLC for net proceeds of $104.6 million. After purchase price adjustments and transaction costs, a gain of $51.1 million was recognized on the sale of these assets ($37.0 million after-tax). The sale of the timber properties completed a reverse like-kind exchange pursuant to Section 1031 of the Internal Revenue Code, as amended (“Reverse 1031 Exchange”). On July 31, 2020, the Company completed its acquisition of certain upstream assets and midstream gathering assets in Pennsylvania from Shell for total consideration of $506.3 million. The purchase and sale agreement with Shell was structured, in part, as a Reverse 1031 Exchange. Refer to Item 8, Note B – Asset Acquisitions and Divestitures, of the Company’s 2020 Form 10-K for additional information concerning the Company’s acquisition of certain upstream assets and midstream gathering assets from Shell.

Project Funding

Over the past two years, the Company has been financing capital expenditures with cash from operations, short-term and long-term debt, common stock, and proceeds from the sale of timber properties. During the nine months ended June 30, 2021 and June 30, 2020, capital expenditures were funded with cash from operations and short-term debt. The Company issued long-term debt and common stock in June 2020 to help finance the acquisition of upstream assets and midstream gathering assets from Shell. The financing of the asset acquisition from Shell was completed in December 2020 when the Company completed the sale of substantially all of its timber properties, through the completion of the Reverse 1031 Exchange discussed above. Going forward, the Company expects to use cash on hand, cash from operations and short-term borrowings to finance capital expenditures. The level of short-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 production and the associated commodity price realizations.

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 and transmission facilities, natural gas gathering and compression facilities and the expansion of natural gas transmission line capacities, regulated utility assets and other opportunities as they may arise. 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 and regulatory conditions.

Financing Cash Flow

Consolidated short-term debt decreased $30.0 million when comparing the balance sheet at June 30, 2021 to the balance sheet at September 30, 2020. The maximum amount of short-term debt outstanding during the nine months ended June 30, 2021 was $145.8 million. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At June 30, 2021, the Company did not have any short-term notes payable to banks or commercial paper outstanding.

The Company maintains $1.0 billion of unsecured committed revolving credit access across two facilities. On October 25, 2018, the Company entered into a Fourth Amended and Restated Credit Agreement ("Credit Agreement") with a syndicate of twelve banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through October 25, 2023. In addition to the Credit Agreement, on February 3, 2021, the Company amended its existing 364-Day Credit Agreement to extend the maturity date thereof from May 3, 2021 to December 30, 2022, and to increase the lenders' commitments thereunder from $200.0 million to $250.0 million, among other changes (as amended, the "Amended 364-Day Credit Agreement"). Twelve banks are parties to the Amended 364-Day Credit Agreement, all of which are also lenders under the Credit Agreement. The Company also has uncommitted lines of credit with financial institutions for general corporate purposes. Borrowings under these uncommitted lines of credit would be made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institution and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines. 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. This provision also applies to the Amended 364-Day Credit Agreement. Since July 1, 2018, the Company recorded non-cash, after-tax ceiling test impairments totaling $381.4 million. As a result, at June 30, 2021, $190.7 million was added back to the Company's total capitalization for purposes of the facility, and the Company's debt to capitalization ratio, as calculated under the facility, was .54. The constraints specified in both the Credit Agreement and Amended 364-Day Credit Agreement would have permitted an additional $1.46 billion in short-term and/or long-term debt to be outstanding at June 30, 2021 (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.

The Credit Agreement and Amended 364-Day Credit Agreement contain 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 and the Amended 364-Day 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.

On February 24, 2021, the Company issued $500.0 million of 2.95% notes due March 1, 2031. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $495.3 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. Additionally, the interest rate payable on the notes will be subject to adjustment from time to time, with a maximum adjustment of 2.00%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes below investment grade (or if the credit rating assigned to the notes is subsequently upgraded). The proceeds of this debt issuance were used for general corporate purposes, including the redemption of $500.0 million of 4.90% notes on March 11, 2021 that were scheduled to mature in December 2021. The Company redeemed those notes for $515.7 million, plus accrued interest.

On June 3, 2020, the Company issued $500.0 million of 5.50% notes due January 15, 2026. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $493.0 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. Additionally, the interest rate payable on the notes will be subject to a maximum adjustment of 2.00% such that the coupon will not exceed 7.50%, if there is a downgrade of the credit rating assigned to the notes. A downgrade with a resulting increase to the coupon does not preclude the coupon from returning to its original rate if the Company's credit rating is subsequently upgraded. The proceeds of this debt issuance were used for general corporate purposes, which included the payment of a portion of the purchase price of the acquisition of Shell's upstream assets and midstream gathering assets in Pennsylvania that closed on July 31, 2020 and the repayment and refinancing of short-term debt.

None of the Company's long-term debt as of June 30, 2021 and September 30, 2020 had a maturity date within the following twelve-month period.

The Company’s embedded cost of long-term debt was 4.48% and 4.85% at June 30, 2021 and June 30, 2020, respectively.

On June 2, 2020, the Company completed a public offering and sale of 4,370,000 shares of the Company's common stock, par value $1.00 per share, at a price of $39.50 per share. After deducting fees, commissions and other issuance costs, the net proceeds to the Company amounted to $165.8 million. The proceeds of this issuance were used to fund a portion of the purchase price of the acquisition of Shell's upstream assets and midstream gathering assets in Pennsylvania that closed on July 31, 2020.

Under the Company’s existing indenture covenants at June 30, 2021, the Company would have been permitted to issue up to a maximum of approximately $300.0 million in additional unsubordinated long-term indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace existing debt. The maximum amount of additional long-term indebtedness noted above that would have been permitted to be issued under the indenture covenants at June 30, 2021 was impacted by non-cash impairments of oil and gas properties recognized during fiscal 2020 and the quarter ended December 31, 2020. The Company's present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants could, for a period of time, prevent the Company from issuing incremental unsubordinated long-term debt, or significantly limit the amount of such debt that could be issued. This would not preclude the Company from issuing new long-term debt to replace existing long-term debt, or from issuing additional short-term 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 3.7%) of the Company’s long-term debt (as of June 30, 2021) 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.

OTHER MATTERS

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

During the nine months ended June 30, 2021, the Company contributed $18.9 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $2.7 million to its VEBA trusts for its other post-retirement benefits. In the remainder of 2021, the Company expects to contribute approximately $1.1 million to its Retirement Plan. In the remainder of 2021, the Company expects to contribute approximately $0.2 million to its VEBA trusts.

The Company, in its Exploration and Production segment, has extended the term of a contractual obligation related to hydraulic fracturing during the quarter ended December 31, 2020. This extension is valued at approximately $82.3 million and extends the contractual obligation through December 31, 2022.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets that are designed to promote transparency, mitigate systemic risk and protect against market abuse. Although regulators have issued certain regulations, other rules that may impact the Company have yet to be finalized.

The CFTC's Dodd-Frank regulations continue to preserve the ability of non-financial end users to hedge their risks using swaps without being subject to mandatory clearing. In 2015, legislation was enacted to exempt from margin requirements swaps used by non-financial end users to hedge or mitigate commercial risk. In 2016, the CFTC issued a reproposal to its position limit rules that would impose speculative position limits on positions in 28 core physical commodity contracts as well as economically equivalent futures, options and swaps. While the Company does not intend to enter into positions on a speculative basis, such rules could nevertheless impact the ability of the Company to enter into certain derivative hedging transactions with respect to such commodities. If the Company reduces its use of hedging transactions as a result of final regulations to be issued by the CFTC, results of operations may become more volatile and cash flows may be less predictable. There may be other rules developed by the CFTC and other regulators that could impact the Company. While many of those rules place specific conditions on the operations of swap dealers and major swap participants, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from final rules through higher transaction costs and prices or other direct or indirect costs.

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

The authoritative guidance for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At June 30, 2021, 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 all other market risk sensitive instruments used by the Company, refer to "Market Risk Sensitive Instruments" in Item 7 of the Company's 2020 Form 10-K.

Rate 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." Neither the New York or Pennsylvania divisions currently have a rate case on file. 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. The order directed the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018.

In New York, on March 13, 2020, in response to the COVID-19 pandemic, the Company agreed to NYPSC Staff's request that the Company suspend service terminations and disconnections. Thereafter, on June 17, 2020, New York enacted a law that prohibits utilities from terminating or disconnecting services to any residential customer for non-payment for the duration of the state disaster emergency. While that legislation expired on March 31, 2021, new legislation was enacted in May 2021 that prohibits utility terminations for non-payment for residential and small commercial customers who experienced a change in financial circumstances due to the COVID-19 state of emergency, with such prohibition running for a period of one hundred eighty days after either the New York State COVID-19 state of emergency is lifted or expires or December 31, 2021, whichever is earlier. On June 24, 2021, the New York State COVID-19 state of emergency expired. Updated guidance issued by the NYPSC on July 6, 2021 confirmed that qualified customers are protected from termination through December 21, 2021 and are eligible for a deferred payment agreement without the requirement of a down payment, late fees, penalties or interest on arrears incurred during the COVID-19 state of emergency. It is uncertain at this point as to whether there would be any regulatory relief for utilities with regard to an increase in costs associated with the COVID-19 pandemic, but it is one of many issues currently being considered in a generic NYPSC proceeding entitled "Proceeding on Motion of the Commission Regarding the Effects of COVID-19 on Utility Service" (Case No. 20-M-0266). Correspondence from NYPSC Staff has recommended that utilities rely on existing avenues of relief for these costs, and has identified additional, more stringent requirements that must be met to achieve relief.

Pennsylvania Jurisdiction

Distribution Corporation's current delivery rates in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007. The rate settlement does not specify any requirement to file a future rate case.

On July 22, 2021, Distribution Corporation filed a supplement to its current Pennsylvania tariff proposing to reduce base rates effective October 1, 2021 by $7.7 million in order to stop collecting other post-employment benefit ("OPEB") expenses from customers at this time, to begin to refund to customers over-collected OPEB expenses in the amount of $50.0 million, and to make certain other adjustments to further reduce Distribution Corporation's regulatory liability associated with OPEB expenses. The refund would be funded entirely by grantor trust assets held by the Company, most of which are included in a fixed income mutual fund that is a component of Other Investments on the Company's Consolidated Balance Sheet. With the elimination of OPEB expenses in base rates, Distribution Corporation would no longer fund the grantor trust or its VEBA trusts in its Pennsylvania jurisdiction. The proposals in the supplement filed by Distribution Corporation are subject to change and require PaPUC approval.

On March 26, 2020, the PaPUC ratified an Emergency Order that established a Service Termination Moratorium intended to continue during the pendency of Governor Wolf's March 6, 2020 Proclamation of Disaster Emergency associated with the COVID-19 pandemic. On May 13, 2020, the Company (and other Pennsylvania local distribution companies) received a Secretarial Letter from the PaPUC regarding COVID-19 pandemic cost tracking and regulatory assets. The Secretarial Letter directs utilities to track "extraordinary, nonrecurring incremental COVID-19 related expenses" so the Commission can understand the impact of these expenses on the utilities' finances. It also authorizes the creation of a utility regulatory asset, but only for incremental uncollectible expenses incurred above those embedded in rates (and incurred since the issuance of the Emergency Order). On October 8, 2020, the Commission issued an order ending the moratorium effective November 9, 2020, imposing a list of enhanced customer protections that expired on March 31, 2021. On March 11, 2021, the Commission adopted an order lifting the utility service termination moratorium effective April 1, 2021, and authorizing utilities to return to the regular collections process with certain modifications to customer payment arrangements. The October and March orders expanded the aforementioned potential utility regulatory asset to include all incremental COVID-19 related expenses incurred above those embedded in rates resulting from directives contained in the orders. The Company continues to monitor this item for potential deferral opportunity.

Pipeline and Storage

Supply Corporation's rate settlement, approved June 1, 2020, provides that no party may make a rate filing for new rates to be effective before February 1, 2024, except that Supply Corporation may file an NGA general Section 4 rate case to change rates if the corporate federal income tax rate is increased. If no case has been filed, Supply Corporation must file for rates to be effective February 1, 2025. Supply has no rate case currently on file.

Empire's 2019 rate settlement provides that Empire must make a rate case filing 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 8 — 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 legislation, legislative proposals and new regulations at the state and federal level, and private party litigation related to greenhouse gas emissions. The U.S. 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 regulates greenhouse gas emissions pursuant to the Clean Air Act. The regulations implemented by EPA impose more stringent leak detection and repair requirements, and further address reporting and control of methane and volatile organic compound emissions. The Company must continue to comply with all applicable regulations. A number of states have adopted energy strategies or plans with aggressive goals for the reduction of greenhouse gas emissions. Pennsylvania has a methane reduction framework with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines and is in the process of evaluating cap-and-trade programs (e.g., Regional Greenhouse Gas Initiative). In California, the Company currently complies with California cap-and-trade rules, which increases the Company's cost of environmental compliance in its Exploration and Production segment. On April 23, 2021, California's Governor issued an executive order directing CalGem to stop issuing fracking permits by 2024, which does not have a direct impact on the plans of the Exploration and Production segment as those plans do not involve fracking. The executive order also directed the California Air Resources Board to investigate phasing out oil extraction by 2045, which may result in permitting delays and new legislative action in support of the directive. Legislation or regulation that aims to reduce greenhouse gas emissions could also include emissions limits, reporting requirements, carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates to conserve energy or use renewable energy sources. Federal, state or local governments may 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. The NYPSC, for example, initiated a proceeding to consider climate-related financial disclosures at the utility operating company level, and the NY State legislature passed the CLCPA that mandates reducing greenhouse gas emissions by 40% from 1990 levels by 2030, and by 85% from 1990 levels by 2050, with the remaining emission reduction achieved by controlled offsets. The CLCPA also requires electric generators to meet 70% of demand with renewable energy by 2030 and 100% with zero emissions generation by 2040. These climate change and greenhouse gas initiatives could impact the Company's customer base and assets depending on the promulgation of final regulations and on regulatory treatment afforded in the process. Thus far, the only regulations promulgated in connection with the CLCPA are greenhouse gas emissions limits established by the NYDEC in 6 NYCRR Part 496, effective December 30, 2020. The NYDEC has until January 1, 2024 to issue further rules and regulations implementing the statute. The above-enumerated initiatives could also increase the Company's cost of environmental compliance by increasing reporting requirements, requiring retrofitting of existing equipment, requiring installation of new equipment, and/or requiring the purchase of emission allowances. They could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals. 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.

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 authoritative accounting and reporting guidance, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words “anticipates,” “estimates,” “expects,” “forecasts,” “intends,” “plans,” “predicts,” “projects,” “believes,” “seeks,” “will,” “may,” and similar expressions, are “forward-looking statements” as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company’s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management’s expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. 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;
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. The length and severity of the ongoing COVID-19 pandemic, including its impacts across our businesses on demand, operations, global supply chains and liquidity;
4. 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;
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. The creditworthiness or performance of the Company’s key suppliers, customers and counterparties;
8. 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;
9. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including disruptions due to the COVID-19 pandemic, as well as difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;
10. The Company's ability to complete planned strategic transactions;
11. The Company's ability to successfully integrate acquired assets and achieve expected cost synergies;
12. 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;
13. The impact of information technology disruptions, cybersecurity or data security breaches;
14. Factors affecting the Company’s ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions,

shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;

15. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits;
16. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;
17. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
18. Uncertainty of oil and gas reserve estimates;
19. Significant differences between the Company's projected and actual production levels for natural gas or oil;
20. Changes in demographic patterns and weather conditions;
21. Changes in the availability, price or accounting treatment of derivative financial instruments;
22. 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;
23. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war;
24. Significant differences between the Company's projected and actual capital expenditures and operating expenses; or
25. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of June 30, 2021.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended June 30, 2021 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 8 – 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 11 – Regulatory Matters.

Item 1A. Risk Factors

The risk factors in Item 1A of the Company's 2020 Form 10-K, as amended by Item 1A of Part II of the Company's Forms 10-Q for the quarters ended December 31, 2020 and March 31, 2021, have not materially changed other than as set forth below. The risk factors presented below supersede the risk factors having the same caption in the 2020 Form 10-K and should otherwise be read in conjunction with all of the risk factors disclosed in the 2020 Form 10-K and the December 31, 2020 and March 31, 2021 Forms 10-Q. The impact of the COVID-19 pandemic may also exacerbate other risks discussed in Item 1A of the Company's 2020 Form 10-K, any of which could have a material effect on us and additional impacts may arise that we are not aware of currently.

The Company may be adversely affected by economic conditions and their impact on our suppliers and customers.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity, including the effects of the COVID-19 pandemic, could adversely affect the Company's revenues and cash flows or restrict its future growth. The Company is monitoring and responding to the impacts of the COVID-19 pandemic across its businesses. To date, the COVID-19 pandemic has not had a material impact on the Company. However, the Company cannot predict the extent or duration of the outbreak or whether this rapidly evolving situation will have a material impact on the Company's workforce, supply chain, operations or financial results, including potential regulatory responses to the financial impacts associated with the COVID-19 pandemic on the Company and its customers. Economic conditions in the Company's utility service territories, along with legislative and regulatory prohibitions and/or limitations on terminations of service, also impact its collections of accounts receivable. For instance, New York initially enacted legislation that prohibits residential utility terminations for non-payment for the duration of the New York State COVID Disaster Emergency and while such legislation expired March 31, 2021, new legislation was enacted in May 2021 that prohibits utility terminations for non-payment for residential and small commercial customers who experienced a change in financial circumstances due to the COVID-19 state of emergency, with such prohibition running for a period of one hundred eighty days after either the New York State COVID-19 state of emergency is lifted or expires or December 31, 2021, whichever is earlier. On June 24, 2021, the New York State COVID-19 state of emergency expired. Shortly thereafter, on July 6, 2021, the NYPSC issued updated guidance confirming that qualified customers are protected from termination through December 21, 2021 and are eligible for a deferred payment agreement without the requirement of a down payment, late fees, penalties or interest on arrears incurred during the COVID-19 state of emergency. All of the Company's segments are exposed to risks associated with the creditworthiness or performance of key suppliers and customers, many of which may be adversely affected by volatile conditions in the financial markets, including volatility caused by the ongoing COVID-19 pandemic. These conditions could result in financial instability or other adverse effects at any of our suppliers or customers. For example, counterparties to the Company's commodity hedging arrangements or commodity sales contracts might not be able to perform their obligations under these arrangements or contracts. Customers of the Company's Utility segment may have particular trouble paying their bills during periods of declining economic activity or high commodity prices, potentially resulting in increased bad debt expense and reduced earnings. The PaPUC has directed utilities to track extraordinary, nonrecurring incremental COVID-19 related expenses, and has authorized the creation of a utility regulatory asset but only for incremental COVID-19 related expenses incurred above those embedded in rates resulting from directives contained in certain PaPUC orders, therefore it is unclear at this time to what extent the PaPUC will, and whether the NYPSC will at all, allow rate recovery for COVID-19 pandemic related expenses. Similarly, if reductions were to occur in funding of the federal Low Income Home Energy Assistance Program, bad debt expense could increase and earnings could decrease. In addition, oil and gas exploration and production companies that are customers of the Company's Pipeline and Storage segment may decide not to renew contracts for the same transportation capacity during periods of reduced production due to persistent low commodity prices. Any of these events could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

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

On April 1, 2021, the Company issued a total of 8,790 unregistered shares of Company common stock to ten non-employee directors of the Company then serving on the Board of Directors of the Company, consisting of 879 shares to each such director. All of these unregistered shares were issued under the Company’s 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors’ services during the quarter ended June 30, 2021. The Company issued an additional 114 shares pursuant to the dividend reinvestment feature of the Company's Non-Employee Directors Deferred Compensation Plan to the six non-employee directors who elected to defer the shares issued for the quarter ended June 30, 2021, consisting of 19 shares to each such director. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased [(a)]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under Share Repurchase Plans or Programs [(b)]
Apr. 1 - 30, 2021	11,479	$50.57	—	6,971,019
May 1 - 31, 2021	11,317	$52.59	—	6,971,019
June 1 - 30, 2021	10,990	$54.55	—	6,971,019
Total	33,786	$52.54	—	6,971,019

(a) Represents (i) shares of common stock of the Company purchased with Company “matching contributions” for the accounts of participants in the Company’s 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock-based compensation awards for the payment of applicable withholding taxes. During the quarter ended June 30, 2021, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 33,786 shares purchased other than through a publicly announced share repurchase program, 33,739 were purchased for the Company's 401(k) plans and 47 were purchased as a result of shares tendered to the Company by holders of stock-based compensation awards.

(b) In September 2008, the Company’s Board of Directors authorized the repurchase of eight million shares of the Company’s common stock. The repurchase program has no expiration date. The Company has not repurchased any shares since September 17, 2008 and has no plans to make further purchases in the near future.

Item 6. Exhibits

Exhibit Number	Description of Exhibit
•	National Fuel Gas Company Deferred Compensation Plan for Directors and Officers (Amended and Restated Effective September 1, 2021) (Exhibit 10.1, Form 8-K dated June 23, 2021)
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statements of Income for the Twelve Months Ended June 30, 2021 and 2020.
101	Interactive data files submitted pursuant to Regulation S-T, formatted in Inline XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the three and nine months ended June 30, 2021 and 2020, (ii) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2021 and 2020, (iii) the Consolidated Balance Sheets at June 30, 2021 and September 30, 2020, (iv) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2021 and 2020 and (v) the Notes to Condensed Consolidated Financial Statements.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document)

• 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.

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/ K. M. Camiolo
K. M. Camiolo
Treasurer and Principal Financial Officer

/s/ E. G. Mendel
E. G. Mendel
Controller and Principal Accounting Officer

Date: August 6, 2021

EXHIBIT 31.1

CERTIFICATION

I, D. P. Bauer, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 6, 2021

/s/ D. P. Bauer
D. P. Bauer
President and Chief Executive Officer

EXHIBIT 31.2

CERTIFICATION

I, K. M. Camiolo, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: August 6, 2021

/s/ K. M. Camiolo

K. M. Camiolo

Treasurer and Principal Financial Officer

EXHIBIT 32

NATIONAL FUEL GAS COMPANY

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

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

1. The Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021 (the "Report") fully complies with the requirements of section 13(a) of the Securities Exchange Act of 1934, as amended; and

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

IN WITNESS WHEREOF, each of the undersigned has executed this statement this 6th day of August, 2021.

/s/ D. P. Bauer
President and Chief Executive Officer

/s/ K. M. Camiolo
Treasurer and Principal Financial Officer

Exhibit 99

NATIONAL FUEL GAS
CONSOLIDATED STATEMENTS OF INCOME
(UNAUDITED)

(Thousands of Dollars)	Twelve Months Ended June 30, 2021	Twelve Months Ended June 30, 2020
INCOME		
Operating Revenues:		
Utility and Energy Marketing Revenues	$ 665,263	$ 730,246
Exploration and Production and Other Revenues	777,744	622,335
Pipeline and Storage and Gathering Revenues	231,653	199,061
	1,674,660	1,551,642
Operating Expenses:		
Purchased Gas	171,244	244,391
Operation and Maintenance:		
Utility and Energy Marketing	181,641	178,321
Exploration and Production and Other	166,834	147,902
Pipeline and Storage and Gathering	118,622	108,415
Property, Franchise and Other Taxes	92,392	88,107
Depreciation, Depletion and Amortization	331,728	300,732
Impairment of Oil and Gas Producing Properties	329,593	195,997
	1,392,054	1,263,865
Gain on Sale of Timber Properties	51,066	—
Operating Income	333,672	287,777
Other Income (Expense):		
Other Income (Deductions)	(14,920)	(16,537)
Interest Expense on Long-Term Debt	(143,455)	(103,451)
Other Interest Expense	(6,832)	(5,944)
Income Before Income Taxes	168,465	161,845
Income Tax Expense	37,325	92,791
Net Income Available for Common Stock	**$ 131,140**	**$ 69,054**
Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$ 1.44	$ 0.80
Diluted:		
Net Income Available for Common Stock	$ 1.43	$ 0.79
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	91,073,766	86,802,706
Used in Diluted Calculation	91,576,260	87,177,232