
UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended September 30, 2020

☐ 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

(State or other jurisdiction of
incorporation or organization)

13-1086010

(I.R.S. Employer
Identification No.)

6363 Main Street

Williamsville, New York

(Address of principal executive offices)

14221

(Zip Code)

(716) 857-7000

(Registrant's telephone number, including area code)

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

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

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☒ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☒

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, a 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to \$3,219,563,000 as of March 31, 2020.

Common Stock, par value \$1.00 per share, outstanding as of October 31, 2020: 90,965,576 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2021 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2020, are incorporated by reference into Part III of this report.

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

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 pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.

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, 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.

Development well A well drilled to a known producing formation in a previously discovered field.

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.

Exploitation Development of a field, including the location, drilling, completion and equipment of wells necessary to produce the commercially recoverable oil and gas in the field.

Exploration costs Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.

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.

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

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)

MMcfe Million cubic feet equivalent

NGA The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.

NYMEX New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.

Open Season A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.

PCB Polychlorinated Biphenyl

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 those reserves productive.

PRP Potentially responsible party

Reliable technology Technology that a company may use to establish reserves estimates and categories that has been proven empirically to lead to correct conclusions.

Reserves The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.

Restructuring Generally referring to partial “deregulation” of the pipeline and/or utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or “unbundling”) of gas commodity service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.

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 Ratings 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.

Spot gas purchases The purchase of natural gas on a short-term basis.

Stock acquisitions Investments in corporations.

Unbundled service A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.

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.

For the Fiscal Year Ended September 30, 2020

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PART I

Item 1 *Business*

The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), incorporated in 1902, is a holding company organized under the laws of the State of New Jersey. The Registrant owns directly or indirectly all of the outstanding securities of its subsidiaries. Reference to “the Company” in this report means the Registrant, the Registrant and its subsidiaries or the Registrant’s subsidiaries as appropriate in the context of the disclosure. Also, all references to a certain year in this report relate to the Company’s fiscal year ended September 30 of that year unless otherwise noted.

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 used for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current natural gas production development activities are focused in the Marcellus and Utica shales, geological shale formations that are present nearly a mile or more below the surface in the Appalachian region of the United States. Pipeline development activities are designed to transport natural gas production to new and growing markets. 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 also develops and produces oil reserves, primarily in California. The Company reports financial results for four business segments: Exploration and Production, Pipeline and Storage, Gathering, and Utility.

1. The Exploration and Production segment operations are carried out by Seneca Resources Company, LLC (Seneca), a Pennsylvania limited liability company. Seneca is engaged in the exploration for, and the development and production of, natural gas and oil reserves in the Appalachian region of the United States and in California. At September 30, 2020, Seneca had proved developed and undeveloped reserves of 3,325,085 MMcf of natural gas and 22,100 Mbbbl of oil.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation (Supply Corporation), a Pennsylvania corporation, and Empire Pipeline, Inc. (Empire), a New York corporation. Supply Corporation and Empire provide interstate natural gas transportation services for affiliated and nonaffiliated companies through integrated gas pipeline systems in Pennsylvania and New York. Supply Corporation also provides storage services through its underground natural gas storage fields.

3. The Gathering segment operations are carried out by wholly-owned subsidiaries of National Fuel Gas Midstream Company, LLC (Midstream Company), a Pennsylvania limited liability company. Through these subsidiaries, Midstream Company builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region.

4. The Utility segment operations are carried out by National Fuel Gas Distribution Corporation (Distribution Corporation), a New York corporation. Distribution Corporation provides natural gas utility services to approximately 747,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

Financial information about each of the Company’s business segments can be found in Item 7, MD&A and also in Item 8 at Note M — Business Segment Information.

Seneca’s Northeast Division is included in the Company’s All Other category. This division markets timber from Appalachian land holdings. At September 30, 2020, the Company owned approximately 95,000 acres of timber property and managed approximately 2,500 additional acres of timber cutting rights. On August 5, 2020, the Company entered into a purchase and sale agreement to sell substantially all timber and other assets. The transaction is expected to close before the end of calendar 2020. For additional discussion of

the purchase and sale agreement to sell these assets, see Item 8 at Note B — Asset Acquisitions and Divestitures.

National Fuel Resources, Inc. (NFR) is included in the Company's All Other category. NFR is the Company's energy marketing subsidiary, which marketed gas to industrial, wholesale, commercial, public authority and residential customers in western and central New York and northwestern Pennsylvania. On August 1, 2020, NFR completed the sale of its commercial and industrial contracts and certain other assets and is now winding down its operations. For additional discussion of this sale, see Item 8 at Note B — Asset Acquisitions and Divestitures.

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2020.

Rates and Regulation

The Company's businesses are subject to regulation under a wide variety of federal, state and local laws, regulations and policies. This includes federal and state agency regulations with respect to rate proceedings, project permitting and environmental requirements.

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. The operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Supply Corporation, Empire or Distribution Corporation are unable to obtain approval from these regulators for the rates they are requesting to charge customers, particularly when necessary to cover increased costs, earnings may decrease. For additional discussion of the Pipeline and Storage and Utility segments' rates, see Item 7, MD&A under the heading "Rate Matters" and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note F — Regulatory Matters.

The discussion under Item 8 at Note F — Regulatory Matters includes a description of the regulatory assets and liabilities reflected on the Company's Consolidated Balance Sheets in accordance with applicable accounting standards. To the extent that the criteria set forth in such accounting standards are not met by the operations of the Utility segment or the Pipeline and Storage segment, as the case may be, the related regulatory assets and liabilities would be eliminated from the Company's Consolidated Balance Sheets and such accounting treatment would be discontinued.

The FERC also exercises jurisdiction over the construction and operation of interstate gas transmission facilities and possesses significant penalty authority with respect to violations of the laws and regulations it administers. The Company is also subject to the jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA issues regulations and conducts evaluations, among other things, that set safety standards for pipelines and underground storage facilities. PHMSA may delegate this authority to a state, as it has in New York and Pennsylvania, and that state may choose to institute more stringent safety regulations for the construction, operation and maintenance of intrastate facilities. In addition to this state safety authority program, the NYPSC imposes additional requirements on the construction of certain utility facilities. Increased regulation by these agencies, or requested changes to construction projects, could lead to operational delays or restrictions and increase compliance costs that the Company may not be able to recover fully through rates or otherwise offset.

For additional discussion of the material effects of compliance with government environmental regulation, see Item 7, MD&A under the heading "Environmental Matters."

The Exploration and Production Segment

The Exploration and Production segment incurred a net loss of \$326.9 million in 2020 (the Company incurred a total consolidated net loss of \$123.8 million in 2020).

Additional discussion of the Exploration and Production segment appears below in this Item 1 under the headings “Sources and Availability of Raw Materials” and “Competition: The Exploration and Production Segment,” in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Pipeline and Storage Segment

The Pipeline and Storage segment contributed net income of \$78.9 million in 2020. This net income partially offset the Company's 2020 net loss.

Supply Corporation's firm transportation capacity is subject to change as the market identifies different transportation paths and receipt/delivery point combinations. At the end of fiscal year 2020, Supply Corporation had firm transportation service agreements and leases for approximately 3,443 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,200 MDth per day or 35% of contracted transportation capacity, and the Exploration and Production segment represents another 74 MDth per day or 2%. Additionally, Supply Corporation leases 55 MDth per day or 2% of its firm transportation capacity to Empire. The remaining 2,114 MDth or 61% is subject to firm contracts or leases with nonaffiliated customers. This amount includes 5 MDth contracted with a former marketing affiliate (NFR) that will be permanently released to a non-affiliated marketer. Contracted transportation capacity with both affiliated and nonaffiliated shippers is expected to remain relatively constant in fiscal 2021.

Supply Corporation had service agreements and leases for all of its firm storage capacity, totaling 70,693 MDth, at the end of 2020. The Utility segment has contracted for 30,064 MDth or 43% of the total firm storage capacity. Additionally, Supply Corporation leases 3,753 MDth or 5% of its firm storage capacity to Empire. Nonaffiliated customers have contracted for the remaining 36,876 MDth or 52%. Supply Corporation expects contracted storage services totaling approximately 867 MDth to terminate and be remarketed in fiscal 2021.

At the end of fiscal 2020, Empire had service agreements in place for firm transportation capacity totaling approximately 984 MDth per day, with 100% of that capacity contracted as long-term, full-year deals. The Utility segment and the Exploration and Production segment account for 7% and 20% of Empire's firm contracted capacity respectively, with the remaining 73% subject to contracts with nonaffiliated customers. Contracted transportation capacity with both affiliated and nonaffiliated shippers is expected to remain relatively constant in fiscal 2021.

Empire's firm storage capacity, totaling 3,753 MDth, was fully contracted at the end of fiscal 2020. The total storage capacity is contracted on a long-term basis, with a nonaffiliated customer. The contract will not expire or terminate in fiscal 2021.

The majority of Supply Corporation's and Empire's transportation and storage contracts allow either party to terminate the contract upon six or twelve months' notice effective at the end of the primary term, and include “evergreen” language that allows for annual term extension(s).

Additional discussion of the Pipeline and Storage segment appears below under the headings “Sources and Availability of Raw Materials,” “Competition: The Pipeline and Storage Segment” and “Seasonality,” in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Gathering Segment

The Gathering segment contributed net income of \$68.6 million in 2020. This net income partially offset the Company's 2020 net loss.

Additional discussion of the Gathering segment appears below under the headings “Sources and Availability of Raw Materials” and “Competition: The Gathering Segment,” in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Utility Segment

The Utility segment contributed net income of \$57.4 million in 2020. This net income partially offset the Company's 2020 net loss.

Additional discussion of the Utility segment appears below under the headings “Sources and Availability of Raw Materials,” “Competition: The Utility Segment” and “Seasonality,” in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss of \$1.8 million in 2020.

Additional discussion of the All Other category and Corporate operations appears below in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

Sources and Availability of Raw Materials

The Exploration and Production segment seeks to discover and produce raw materials (natural gas, oil and hydrocarbon liquids) as further described in this report in Item 7, MD&A and Item 8 at Note M — Business Segment Information and Note O — Supplementary Information for Oil and Gas Producing Activities.

The Pipeline and Storage segment transports and stores natural gas owned by its customers, whose gas primarily originates in the Appalachian region of the United States, as well as other gas supply regions in the United States and Canada. Additional discussion of proposed pipeline projects appears below under “Competition: The Pipeline and Storage Segment” and in Item 7, MD&A.

The Gathering segment gathers, processes and transports natural gas that is produced by Seneca in the Appalachian region of the United States. Additional discussion of proposed gathering projects appears below in Item 7, MD&A.

Natural gas is the principal raw material for the Utility segment. In 2020, the Utility segment purchased 73.4 Bcf of gas (including 70.3 Bcf for delivery to retail customers and 3.1 Bcf used in operations) pursuant to its purchase contracts with firm delivery requirements. Gas purchased from producers and suppliers in the United States under multi-month contracts accounted for 52% of these purchases. Purchases of gas in the spot market (contracts of one month or less) accounted for 48% of the Utility segment's 2020 purchases. Purchases from DTE Energy Trading, Inc. (38%), Emera Energy Services, Inc. (18%), Shell Energy North America US (8%), Chevron Natural Gas (5%) and Tenaska Marketing Ventures (5%) accounted for nearly 75% of the Utility segment's 2020 gas purchases. No other producer or supplier provided the Utility segment with more than 5% of its gas requirements in 2020.

Competition

Competition in the natural gas industry exists among providers of natural gas, as well as between natural gas and other sources of energy, such as fuel oil and electricity. Management believes that the environmental advantages of natural gas have enhanced its competitive position relative to other fuels.

The Company competes on the basis of price, service and reliability, product performance and other factors. Sources and providers of energy, other than those described under this “Competition” heading, do not compete with the Company to any significant extent.

Competition: The Exploration and Production Segment

The Exploration and Production segment competes with other oil and natural gas producers and marketers with respect to sales of oil and natural gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other oil and natural gas producers with respect to exploration and development prospects and mineral leaseholds.

To compete in this environment, Seneca originates and acts primarily as operator on its prospects, seeks to minimize the risk of exploratory efforts through partnership-type arrangements, utilizes technology for both exploratory studies and drilling operations, and seeks opportunities based on size, operating expertise and financial criteria.

Competition: The Pipeline and Storage Segment

Supply Corporation competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and with other companies providing gas storage services. Supply Corporation has some unique characteristics which enhance its competitive position. Most of Supply Corporation's facilities are in or near areas overlying the Marcellus and Utica Shale production areas in Pennsylvania, and it has established interconnections with producers and other pipelines to access these supplies. Its facilities are also located adjacent to the Canadian border at the Niagara River providing access to markets in Canada and the northeastern and midwestern United States via the TC Energy pipeline system. Supply Corporation has developed and placed into service a number of pipeline expansion projects designed to transport natural gas to key markets in New York, Pennsylvania, the northeastern United States, Canada, and to long-haul pipelines with access to the U.S. Midwest and the gulf coast. For further discussion of Pipeline and Storage projects, refer to Item 7, MD&A under the heading "Investing Cash Flow."

Empire competes for natural gas market growth with other pipeline companies transporting gas in the northeast United States and upstate New York in particular. Empire is well situated to provide transportation of Appalachian shale gas as well as gas supplies available at Empire's interconnect with TC Energy at Chippawa. Empire's geographic location provides it the opportunity to compete for service to its on-system LDC markets, as well as for a share of the gas transportation markets into Canada (via Chippawa) and into the northeastern United States. The Empire Connector, along with other subsequent projects, has expanded Empire's footprint and capability, allowing Empire to serve new markets in New York and elsewhere in the Northeast, and to attach to prolific Marcellus and Utica supplies principally from Tioga and Bradford Counties in Pennsylvania. Like Supply Corporation, Empire's expanded system facilitates transportation of shale gas to key markets within New York State, the northeastern United States and Canada.

Competition: The Gathering Segment

The Gathering segment principally provides gathering services for Seneca's production and competes with other companies that gather and process natural gas in the Appalachian region.

Competition: The Utility Segment

With respect to gas commodity service, in New York and Pennsylvania, both of which have implemented "unbundling" policies that allow customers to choose their gas commodity supplier, Distribution Corporation has retained a substantial majority of small sales customers. In both New York and Pennsylvania, approximately 9% of Distribution Corporation's small-volume residential and commercial customers purchase their supplies from unregulated marketers. In contrast, almost all large-volume load is served by unregulated retail marketers. However, retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation, because in both jurisdictions, utility cost of service is recovered through rates and charges for gas delivery service, not gas commodity service.

Competition for transportation service to large-volume customers continues with local producers or pipeline companies attempting to sell or transport gas directly to end-users located within the Utility segment's service territories without use of the utility's facilities (i.e., bypass). In addition, while competition with fuel oil suppliers exists, recent commodity pricing has enhanced the competitive position of natural gas.

The Utility segment competes in its most vulnerable markets (the large commercial and industrial markets) by offering unbundled, flexible, high quality services. The Utility segment continues to advance programs promoting the efficient use of natural gas.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation in jurisdictions that impact the Utility segment. New York, for

example, adopted the Climate Leadership & Community Protection Act (CLCPA) in July 2019, which could ultimately result in increased competition from electric and geothermal forms of energy. However, given the extended time frames associated with the CLCPA's emission reduction mandates as discussed in Item 7, MD&A under the heading "Environmental Matters" and subheading "Environmental Regulation," any meaningful competition resulting from the CLCPA cannot be determined.

Seasonality

Variations in weather conditions can materially affect the volume of natural gas delivered by the Utility segment, as virtually all of its residential and commercial customers use natural gas for space heating. The effect that this has on Utility segment margins in New York is mitigated by a weather normalization clause (WNC), which covers the eight-month period from October through May. Weather that is warmer than normal results in an upward adjustment to customers' current bills, while weather that is colder than normal results in a downward adjustment, so that in either case projected operating costs calculated at normal temperatures will be recovered.

Volumes transported and stored by Supply Corporation and by Empire may vary significantly depending on weather, without materially affecting the revenues of those companies. Supply Corporation's and Empire's allowed rates are based on a straight fixed-variable rate design which allows recovery of fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover only the variable costs associated with actual transportation or storage of gas.

Capital Expenditures

A discussion of capital expenditures by business segment is included in Item 7, MD&A under the heading "Investing Cash Flow."

Environmental Matters

A discussion of material environmental matters involving the Company is included in Item 7, MD&A under the heading "Environmental Matters" and in Item 8, Note L — Commitments and Contingencies.

Miscellaneous

The Utility segment has numerous municipal franchises under which it uses public roads and certain other rights-of-way and public property for the location of facilities. When necessary, the Utility segment renews such franchises.

The Company makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on the Company's website, www.nationalfuelgas.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. The information available at the Company's website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

Human Capital

The Company aims to attract the best employees, to retain those employees through offering career development and training opportunities while also prioritizing their safety and wellness, and to create a safe, inclusive and productive work environment for everyone. Human capital measures and objectives that the Company focuses on in managing its business include the safety of its employees, its voluntary attrition rate, the number of work stoppages, its employee benefits, employee development, and diversity and inclusion. Additional information regarding the Company's human capital measures and objectives is contained in the Company's 2019 Corporate Responsibility Report, which is available on the Company's website, www.nationalfuelgas.com. The information on the Company's website is not, and will not be deemed to be, a part of this annual report on Form 10-K or incorporated into any of the Company's other filings with the SEC.

Employees and Collective Bargaining Agreements

The Company and its wholly-owned subsidiaries had a total of 2,162 full-time employees at September 30, 2020.

As of September 30, 2020, 48% of the Company's active workforce was covered under collective bargaining agreements. The Company has agreements in place with collective bargaining units in New York and Pennsylvania. Agreements covering employees in collective bargaining units in New York are scheduled to expire in February 2021. The Company has been preparing for contract negotiations with these bargaining units and formal negotiation discussions are scheduled to begin in November 2020. Agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2022.

Safety

Safety is one of the Company's guiding principles. In managing the business, the Company focuses on the safety of its employees and has implemented safety programs and management practices to promote a culture of safety. This includes required trainings for both field and office employees, as well as specific qualifications and certifications for field employees. The Company also ties executive compensation to safety related goals to emphasize the importance of and focus on safety at the Company.

Voluntary Attrition Rate

The Company measures the voluntary attrition rate of its employees in assessing the Company's overall human capital. The Company believes that its fiscal year voluntary attrition rate (not including retirements) of 4.4% is better than that of the Company's industry. Additionally, throughout the COVID-19 pandemic, the Company has not instituted any furloughs or workforce reductions.

No Work Stoppages

During the Company's fiscal year, the Company did not incur any work stoppages (strikes or lockouts) and therefore experienced zero idle days for the fiscal year.

Employee Benefits

To attract employees and meet the needs of the Company's workforce, the Company offers benefits packages to employees of its subsidiaries. The Company's benefits package options may vary depending on type of employee (full-time versus part-time) and date of hire. Additionally, the Company continuously looks for ways to improve employee work-life balance and well-being.

Employee Development

The Company provides its employees with tools and development resources to enhance their skills and careers at the Company, including: (i) encouraging employees to discuss their professional development and identify interests or possible cross-training areas during annual performance reviews with their supervisors; (ii) offering corporate and technical training programs based on position, regulatory environment, and employee needs; (iii) providing a tuition aid program for educational pursuits related to present work or possible future positions; (iv) providing talent review and succession planning; (v) providing opportunities for on-the-job growth, through stretch assignments or temporary projects outside of an employee's typical responsibilities; and (vi) offering one-on-one meetings for supervisory employees at the Company's regulated subsidiaries to discuss career pathing and employee development.

Diversity and Inclusion

The Company recognizes that a diverse talent pool provides the opportunity to gain a diversity of perspectives, ideas and solutions to help the Company succeed. The Company considers diversity when making hiring and promotional decisions. The Company's commitment to diversity also extends to the Board of Directors.

To attract diverse candidates, the Company works with community groups and organizations to help promote awareness of job opportunities within diverse communities. The Company's participation in

community outreach events to educate job seekers about its commitment to equitable employee representation, as well as its sponsorship of scholarship programs for underrepresented minority individuals pursuing science, technology, engineering, math or business related fields, reflect the Company's commitment to the attraction of diverse candidates. In addition, the Company has several policies that reinforce its commitment to diversity and inclusion within the workplace. The Company's Employee Handbook Policy includes equal employment opportunity commitments and nondiscrimination and anti-harassment disclosures, which communicate the Company's expectations with respect to maintaining a professional workplace free of harassment. The Company prohibits discrimination or harassment against any employee or applicant on the basis of sex, race/ethnicity, or the other protected categories listed within the Company's Non-Discrimination and Anti-Harassment Policy. The Company is committed to a harassment free workplace, which is supported through prevention training for employees. Additionally, the Company recently required all officers to participate in racial equity analysis training. Annually, the Company's Chief Executive Officer reinforces the Company's commitment to equal employment opportunity by signing a corporate Equal Employment Opportunity policy statement. This statement is then displayed at Company locations, included in employee handbooks, and discussed with new hires during their onboarding process and employees annually through the employee survey and attestation process.

Executive Officers of the Company as of November 15, 2020(1)

Name and Age (as of November 15, 2020)	Current Company Positions and Other Material Business Experience During Past Five Years
David P. Bauer (51)	Chief Executive Officer of the Company since July 2019. President of Supply Corporation from February 2016 through June 2019. Treasurer and Principal Financial Officer of the Company from July 2010 through June 2019. Treasurer of Seneca from April 2015 through June 2019. Treasurer of Distribution Corporation from April 2015 through June 2019. Treasurer of Midstream Company from April 2013 through June 2019. Treasurer of Supply Corporation from June 2007 through June 2019. Treasurer of Empire from June 2007 through June 2019.
John R. Pustulka (68)	Chief Operating Officer of the Company since February 2016. Mr. Pustulka previously served as President of Supply Corporation from July 2010 through January 2016.
Donna L. DeCarolis (61)	President of Distribution Corporation since February 2019. Ms. DeCarolis previously served as Vice President of Business Development of the Company from October 2007 through January 2019.
Michael P. Kasprzak (62)	President of Midstream Company since August 2018. Vice President of Midstream Company from July 2017 through July 2018. Mr. Kasprzak previously served as Assistant Vice President of Supply Corporation from March 2009 until July 2017.
Ronald C. Kraemer (64)	President of Supply Corporation since July 2019 and President of Empire since August 2008. Mr. Kraemer previously served as Senior Vice President of Supply Corporation from June 2016 through June 2019 and as Vice President of Supply Corporation from August 2008 through May 2016.
John P. McGinnis (60)	President of Seneca since May 2016. Mr. McGinnis previously served as Chief Operating Officer of Seneca from October 2015 through April 2016.
Karen M. Camiolo (61)	Treasurer and Principal Financial Officer of the Company since July 2019. Treasurer of Distribution Corporation, Supply Corporation, Empire, Seneca and Midstream Company since July 2019. Ms. Camiolo previously served as Controller and Principal Accounting Officer of the Company from April 2004 through June 2019. Vice President of Distribution Corporation from April 2015 through June 2019. Contoller of Midstream Company from April 2013 through June 2019. Contoller of Empire from June 2007 through June 2019. Contoller of Distribution Corporation and Supply Corporation from April 2004 through June 2019.
Elena G. Mendel (54)	Controller and Principal Accounting Officer of the Company since July 2019. Controller of Distribution Corporation, Supply Corporation, Empire, and Midstream Company since July 2019. Assistant Controller of Distribution Corporation, Supply Corporation and Empire from February 2017 through June 2019. Ms. Mendel also previously served as Chief Auditor of the Company from July 2012 through January 2017.
Martin A. Krebs (50)	Chief Information Officer of the Company since December 2018. Prior to joining the Company, Mr. Krebs served as Chief Information Officer and Chief Information Security Officer of Fidelis Care, a health insurance provider for New York State residents, from January 2012 to June 2018. Centene Corporation acquired Fidelis Care in July 2018, and Mr. Krebs served as the Chief Information Officer of the Fidelis Plan and Senior Vice President of Information Technology and Security from the acquisition to November 2018. Mr. Krebs's prior employers are not subsidiaries or affiliates of the Company.
Sarah J. Mugel (56)	General Counsel of the Company since May 2020 and Secretary of the Company since July 2018. Ms. Mugel has been Vice President of Supply Corporation since April 2015 and General Counsel and Secretary of Supply Corporation since April 2016. Ms. Mugel has been Secretary of Empire Pipeline and Secretary of Midstream Company, and has served as the General Counsel of both entities, since April 2016. Ms. Mugel previously served as Assistant Secretary of the Company from June 2016 through June 2018 and as Assistant Secretary of Supply Corporation from April 2015 through March 2016.

- (1) The executive officers serve at the pleasure of the Board of Directors. The information provided relates to the Company and its principal subsidiaries. Many of the executive officers also have served or currently serve as officers or directors of other subsidiaries of the Company.

Item 1A Risk Factors

STRATEGIC RISKS

The Company is dependent on capital and credit markets to successfully execute its business strategies.

The Company relies upon short-term bank borrowings, commercial paper markets and longer-term capital markets to finance capital requirements not satisfied by cash flow from operations. The Company is dependent on these capital sources to provide capital to its subsidiaries to fund operations, acquire, maintain and develop properties, and execute growth strategies. The availability and cost of credit sources may be cyclical and these capital sources may not remain available to the Company. Continued turmoil in credit markets, due to the ongoing COVID-19 pandemic or otherwise, may make it difficult for the Company to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance maturing debt. These difficulties could adversely affect the Company's growth strategies, operations and financial performance.

The Company's ability to borrow under its credit facilities and commercial paper agreements, and its ability to issue long-term debt under its indentures, depend on the Company's compliance with its obligations under the facilities, agreements and indentures. For example, to issue incremental long-term debt, the Company must meet an interest coverage test under its 1974 indenture. In general, the Company's operating income, subject to certain adjustments, over a consecutive 12-month period within the 15 months preceding the debt issuance, must be not less than two times the total annual interest charges on the Company's long-term debt, taking into account the incremental issuance. In addition, the Company must maintain a ratio of long-term debt to consolidated assets (as defined under the 1974 indenture) of not more than 60%. Depending on their magnitude, factors that reduce the Company's operating income and/or consolidated assets, including impairments (i.e., write-downs) of the Company's oil and natural gas properties, could contribute to the Company's inability to meet the interest coverage test or debt-to-assets ratio. In light of impairments recognized in fiscal 2020, and potentially in fiscal 2021, the Company will be precluded from issuing incremental long-term debt for several quarters in fiscal 2021. The 1974 indenture would not preclude the Company from issuing long-term debt to replace maturing long-term debt, including the Company's 4.90% notes, in the principal amount of \$500 million, maturing in December 2021.

In addition, the Company's short-term bank loans and commercial paper are in the form of floating rate debt or debt that may have rates fixed for very short periods of time, resulting in exposure to interest rate fluctuations in the absence of interest rate hedging transactions. The cost of long-term debt, the interest rates on the Company's short-term bank loans and commercial paper and the ability of the Company to issue commercial paper are affected by its credit ratings published by S&P, Moody's Investors Service, Inc. and Fitch Ratings. 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. On March 27, 2020, the Company was downgraded by S&P to a rating of BBB- with a negative outlook, which S&P revised on June 3, 2020 to a rating of BBB- with a stable outlook. Combined with current ratings from other credit rating agencies, that downgrade increased the Company's short-term borrowing costs under its Credit Agreement. Additionally, \$600 million of the Company's outstanding long-term debt would be subject to an interest rate increase if certain fundamental changes occur that involve a material subsidiary and result in a downgrade of a credit rating assigned to the notes below investment grade. In addition to the \$600 million, another \$500 million of the Company's outstanding long-term debt would be subject to an interest rate increase based solely on a downgrade of a credit rating assigned to the notes below investment grade, regardless of any additional fundamental changes. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets.

Climate change, and the regulatory, legislative and capital access developments related to climate change, may adversely affect operations and financial results.

Climate change could create physical risks, which may adversely affect the Company's operations. Physical risks include changes in weather conditions, which could cause demand for gas to increase or decrease. If there were to be any impacts from climate change to the Company's operations and financial results, the Company expects that they would likely occur over a long period of time and thus are difficult to quantify with any degree of specificity. Extreme weather events may result in adverse physical effects on portions of the country's gas infrastructure, which could disrupt the Company's supply chain and ultimately its operations. Disruption of production activities, and transportation and distribution systems could result in reduced operational efficiency, and customer service interruption.

Climate change, and the laws, regulations and other initiatives to address climate change, may impact the Company's financial results. On November 4, 2020, the U.S. withdrew from the Paris Agreement, the international effort to establish emissions reduction goals for signatory countries. It is not possible at this time to predict whether changes in the federal administration may change the country's participation in or the terms on which the U.S. may reenter the Paris Agreement. Despite the recent federal withdrawal, state and local governments, non-governmental organizations, and financial institutions have made, and will likely continue to make, more aggressive efforts to reduce emissions and advance the objectives of the Paris Agreement. Federal, state and local legislative and regulatory initiatives proposed or adopted in recent years in an attempt to limit the effects of climate change, including greenhouse gas emissions, could have significant impacts on the energy industry including government-imposed limitations, prohibitions or moratoriums on the use of gas and oil as well as accelerated depreciation of assets and/or stranded assets. For example, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. A number of states have adopted energy strategies or plans with goals that include the reduction of greenhouse gas emissions. For example, Pennsylvania has a methane reduction framework for the oil and gas industry which has resulted in permitting changes with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines. With respect to its operations in California, the Company currently complies with California cap-and-trade guidelines, which increases the Company's cost of environmental compliance in its Exploration and Production segment operation. In addition, the NYPSC initiated a proceeding to consider climate-related financial disclosures at the utility operating level, and the NY State legislature passed the CLCPA, which created emission reduction and electric generation mandates, and could ultimately impact the Utility segment's customer base and the Utility segment's business. Legislation or regulation that aims to reduce greenhouse gas emissions could also include greenhouse gas emissions limits and reporting requirements, carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates to conserve energy or use renewable energy sources. Additionally, the trend toward increased conservation, competition from renewable energy sources, and technological advances to address climate change may reduce the demand for natural gas. For further discussion of the risks associated with environmental regulation to address climate change, refer to Item 7, MD&A under the heading "Environmental Matters" and subheading "Environmental Regulation."

Further, recent trends directed toward a low-carbon economy could shift funding away from, or limit or restrict certain sources of funding for, companies focused on fossil fuel-related development or carbon-intensive investments. To the extent financial markets view climate change and greenhouse gas emissions as a financial risk, the Company's cost of and access to capital could be negatively impacted.

Organized opposition to the oil and gas industry could have an adverse effect on Company operations.

Organized opposition to the oil and gas industry, including exploration and production activity and pipeline expansion and replacement projects, may continue to increase as a result of, among other things, safety incidents involving gas facilities, and concerns raised by politicians, financial institutions and advocacy groups about greenhouse gas emissions, hydraulic fracturing, or fossil fuels generally. This opposition may lead to increased regulatory and legislative initiatives that could place limitations, prohibitions or moratoriums on the use of gas and oil, impose costs tied to carbon emissions, provide cost advantages to alternative energy sources, or impose mandates that increase operational costs associated with new natural gas infrastructure and

technology. This opposition may also lead to increased litigation that could cause operational delays or restrictions, and increase the Company's operating costs. In turn, these factors could impact the competitive position of natural gas, ultimately affecting the Company's results of operations and cash flows.

Delays or changes in plans or costs with respect to Company projects, including regulatory delays or denials with respect to necessary approvals, permits or orders, could delay or prevent anticipated project completion and may result in asset write-offs and reduced earnings.

Construction of the Pipeline and Storage segment's planned pipelines and storage facilities, as well as the expansion of existing facilities, is subject to various regulatory, environmental, political, legal, economic and other development risks, including the ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on acceptable terms, or at all. Existing or potential third party opposition, such as opposition from landowner and environmental groups, which are beyond our control, could materially affect the anticipated construction of a project. In addition, third parties could impede the Gathering segment's acquisition, expansion or renewal of rights-of-way or land rights on a timely basis and on acceptable terms. Any delay in project construction may prevent a planned project from going into service when anticipated, which could cause a delay in the receipt of revenues from those facilities, result in asset write-offs and materially impact operating results or anticipated results. Additionally, delays in pipeline construction projects could impede the Exploration and Production segment's ability to transport its production to premium markets, or to fulfill obligations to sell at contracted delivery points.

FINANCIAL RISKS

As a holding company, the Company depends on its operating subsidiaries to meet its financial obligations.

The Company is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, the Company relies exclusively on repayments of principal and interest on intercompany loans made by the Company to its operating subsidiaries and income from dividends. Such operating subsidiaries may not generate sufficient net income to pay upstream dividends or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

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 on terminations of service, also impact its collections of accounts receivable. For instance, New York enacted legislation in June 2020 that prohibits residential utility terminations for nonpayment for the duration of the New York State COVID Disaster Emergency (currently running until December 3, 2020), and thereafter, the law prohibits terminations for nonpayment through March 31, 2021 for residential customers that attest to Distribution that they have experienced a change in financial circumstances due to 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 uncollectible expenses incurred above those embedded in rates, 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.

Changes in interest rates may affect the Company's financing and its regulated businesses' rates of return.

Rising interest rates may impair the Company's ability to cost-effectively finance capital expenditures and to refinance maturing debt. In addition, the Company's authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, the Company's authorized rate of return could be reduced. If interest rates are higher than assumed rates, the Company's ability to earn its authorized rate of return may be adversely impacted.

Fluctuations in oil and gas prices could adversely affect revenues, cash flows and profitability.

Operations in the Company's Exploration and Production segment are materially dependent on prices received for its oil and gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and gas. Oil and gas prices can be volatile and can be affected by: weather conditions, natural disasters, the supply and price of foreign oil and gas, the level of consumer product demand, national and worldwide economic conditions, economic disruptions caused by terrorist activities, acts of war or major accidents, political conditions in foreign countries, the price and availability of alternative fuels, the proximity to, and availability of, sufficient capacity on transportation facilities, regional levels of supply and demand, energy conservation measures, and government regulations. The Company sells the oil and gas that it produces at a combination of current market prices, indexed prices or through fixed-price contracts. The Company hedges a significant portion of future sales that are based on indexed prices utilizing the physical sale counter-party or the financial markets. The prices the Company receives depend upon factors beyond the Company's control, including the factors affecting price mentioned above. The Company believes that any prolonged reduction in oil and gas prices could restrict its ability to continue the level of exploration and production activity the Company otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.

In the Company's Pipeline and Storage segment, significant changes in the price differential between equivalent quantities of gas at different geographic locations could adversely impact the Company. For example, if the price of gas at a particular receipt point on the Company's pipeline system increases relative to the price of gas at other locations, then the volume of gas received by the Company at the relatively more expensive receipt point may decrease, or the price the Company charges to transport that gas may decrease. Changes in price differentials can cause shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. In some cases, shippers may decide not to renew transportation contracts due to changes in price differentials. While much of the impact of lower volumes under existing contracts would be offset by the straight fixed-variable rate design, this rate design does not protect Supply Corporation or Empire where shippers do not contract for expiring capacity at the same quantity and rate. If contract renewals were to decrease, revenues and earnings in this segment may decrease. Significant changes in the price differential between futures contracts for gas having different delivery dates could also adversely impact the Company. For example, if the prices of gas futures contracts for winter deliveries to locations served by the Pipeline and Storage segment decline relative to the prices of such contracts for summer deliveries (as a result, for instance, of increased production of gas within the segment's geographic area or other factors), then

demand for the Company's gas storage services driven by that price differential could decrease. These changes could adversely affect revenues, cash flows and results of operations.

The Company has significant transactions involving price hedging of its oil and gas production as well as its fixed price sale commitments.

To protect itself to some extent against unusual price volatility and to lock in fixed pricing on oil and gas production for certain periods of time, the Company's Exploration and Production segment regularly enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may extend over multiple years, covering as much as approximately 80% of the Company's expected energy production during the current fiscal year, and lesser percentages of subsequent years' expected production. These contracts reduce exposure to subsequent price drops but can also limit the Company's ability to benefit from increases in commodity prices.

Use of energy commodity price hedges also exposes the Company to the risk of nonperformance by a contract counterparty. These parties might not be able to perform their obligations under the hedge arrangements.

It is the Company's practice that the use of commodity derivatives contracts comply with various policies in effect in respective business segments. For example, in the Exploration and Production segment, commodity derivatives contracts must be confined to the price hedging of existing and forecast production. The Company maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose the Company to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of oil and gas falls short of hedged forecast production, the Company may incur substantial losses to cover its hedges.

The Dodd-Frank Act increased federal oversight and regulation of the over-the-counter derivatives markets and certain entities that participate in those markets. Although regulators have issued certain regulations, other rules that may be relevant to the Company have yet to be finalized. For discussion of the risks associated with the Dodd-Frank Act, refer to Item 7, MD&A under the heading "Market Risk Sensitive Instruments."

You should not place undue reliance on reserve information because such information represents estimates.

This Form 10-K contains estimates of the Company's proved oil and gas reserves and the future net cash flows from those reserves, which the Company's petroleum engineers prepared and independent petroleum engineers audited. Petroleum engineers consider many factors and make assumptions in estimating oil and gas reserves and future net cash flows. These factors include: historical production from the area compared with production from other producing areas; the assumed effect of governmental regulation; and assumptions concerning oil and gas prices, production and development costs, severance and excise taxes, and capital expenditures. Lower oil and gas prices generally cause estimates of proved reserves to be lower. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to the Company's reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of the Company's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

If conditions remain constant, then the Company is reasonably certain that its reserve estimates represent economically recoverable oil and gas reserves and future net cash flows. If conditions change in the future, then subsequent reserve estimates may be revised accordingly. You should not assume that the present value of future net cash flows from the Company's proved reserves is the current market value of the Company's estimated oil and gas reserves. In accordance with SEC requirements, the Company bases the estimated discounted future net cash flows from its proved reserves on a 12-month average of historical prices for oil and gas (based on first day of the month prices and adjusted for hedging) and on costs as of the date of the estimate, which are all discounted at the SEC mandated discount rate. Actual future prices and costs may differ materially

from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of the Company's reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating oil and gas reserves is complex. The process involves significant assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to the Company's reserve estimates in the future. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of oil and gas that are ultimately recovered, the timing of the recovery of oil and gas reserves, the production and operating costs to be incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

Financial accounting requirements regarding exploration and production activities may affect the Company's profitability.

The Company accounts for its exploration and production activities under the full cost method of accounting. Each quarter, the Company must perform a "ceiling test" calculation, comparing the level of its unamortized investment in oil and gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses a 12-month historical average price for oil and gas (based on first day of the month prices and adjusted for hedging) as well as the SEC mandated discount rate. If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material. Under the Company's existing indenture covenants, an impairment could restrict the Company's ability to issue incremental long-term unsecured indebtedness for a period of time, beginning with the fourth calendar month following the impairment. For the quarter and fiscal year ended September 30, 2020, the Company recognized pre-tax impairment charges on its oil and natural gas properties of \$253.4 million and \$449.4 million, respectively, and the Company will be precluded from issuing incremental long-term unsecured indebtedness for several quarters in fiscal 2021. The Company could potentially record non-cash impairments in future quarters depending on the commodity price environment.

OPERATIONAL RISKS

The COVID-19 global pandemic could have a material adverse effect on the Company's business, results of operations, cash flows and financial condition.

The actual or perceived effects of a widespread public health concern or pandemic, such as COVID-19, could negatively affect our business and results of operations. While to date the Company has not experienced any material negative effects as a result of the COVID-19 pandemic, the situation continues to rapidly evolve and could result in material negative effects on our business and results of operations. The Company and its Pandemic Response Team are closely monitoring and responding to the impacts of the pandemic on the Company's workforce, customers, contractors, suppliers, business continuity, and liquidity.

The protracted slowdown of broad sectors of the economy as a result of the COVID-19 pandemic has decreased the current demand for oil and has the potential to decrease the demand for natural gas, which could reduce the Company's revenues. Additionally, significant changes in legislation or regulatory policy to address the COVID-19 pandemic could adversely impact the Company. Although it is not possible to predict the ultimate impact of the COVID-19 pandemic, including on the Company's business, results of operations, cash flows or financial positions, such impacts that may be material include, but are not limited to: (i) a significant reduction in near-term demand for natural gas and/or oil; (ii) increased late or uncollectible customer payments;

(iii) the inability for the Company's contractors or suppliers to fulfill their contractual obligations; (iv) significant changes in the Company's human capital management approach, increased cybersecurity threats associated with work-from-home arrangements, and increased purchases of personal protective equipment as the Company prepares its return-to-work plan; (v) difficulties in obtaining financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance maturing debt; and (vi) impacts on natural gas and oil pricing and the potential impairment of the recorded value of certain assets as a result of reduced projected cash flows. To the extent the duration of any of these conditions extends for a longer period of time, the adverse impact will generally be more severe.

The nature of the Company's operations presents inherent risks of loss that could adversely affect its results of operations, financial condition and cash flows.

The Company's operations in its various reporting segments are subject to inherent hazards and risks such as: fires; natural disasters; explosions; blowouts during well drilling; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage, environmental damage or business interruption losses. Additionally, the Company's facilities, machinery, and equipment may be subject to sabotage. These events, in turn, could lead to governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, the Company maintains insurance coverage against some, but not all, potential losses. The Company also seeks, but may be unable, to secure written indemnification agreements with contractors that adequately protect the Company against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, the imposition of fines, penalties or mandated programs by governmental authorities, the failure of a contractor to meet its indemnification obligations, or the failure of an insurance company to pay valid claims could result in substantial losses to the Company. In addition, insurance may not be available, or if available may not be adequate, to cover any or all of these risks. It is also possible that insurance premiums or other costs may rise significantly in the future, so as to make such insurance prohibitively expensive.

Hazards and risks faced by the Company, and insurance and indemnification obtained or provided by the Company, may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against the Company or be resolved on unfavorable terms, the result of which could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

Third party attempts to breach the Company's network security could disrupt the Company's operations and adversely affect its financial results.

The Company's information technology systems are subject to attempts by others to gain unauthorized access, or to otherwise introduce malicious software. These attempts might be the result of industrial or other espionage, or actions by hackers seeking to harm the Company, its services or customers. These more sophisticated cyber-related attacks, as well as cybersecurity failures resulting from human error, pose a risk to the security of the Company's systems and networks and the confidentiality, availability and integrity of the Company's and its customers' data. That data may be considered sensitive, confidential, or personal information that is subject to privacy and security laws and regulations. While the Company employs reasonable and appropriate controls to protect data and the Company's systems, the Company may be vulnerable to material security breaches, lost or corrupted data, programming errors and employee errors and/or malfeasance that could lead to the unauthorized access, use, disclosure, modification or destruction of the sensitive, confidential or personal information. Attempts to breach the Company's network security may result in disruption of the Company's business operations and services, delays in production, theft of sensitive and valuable data, damage to our physical systems, and reputational harm. Significant expenditures may be required to remedy breaches, including restoration of customer service and enhancement of information technology systems. The Company seeks to prevent, detect and investigate these security incidents, but in some cases the Company might be unaware of an incident or its magnitude and effects. In addition to existing risks, the adoption of new technologies may also increase the Company's exposure to data breaches or the Company's ability to detect and remediate effects of a breach. The Company has experienced attempts to breach its network security and has

received notifications from third-party service providers who have experienced data breaches where Company data was potentially impacted. Although the scope of such incidents is sometimes unknown, they could prove to be material to the Company. Even though insurance coverage is in place for cyber-related risks, if such a breach were to occur, the Company's operations, earnings and financial condition could be adversely affected to the extent not fully covered by such insurance.

The amount and timing of actual future oil and gas production and the cost of drilling are difficult to predict and may vary significantly from reserves and production estimates, which may reduce the Company's earnings.

There are many risks in developing oil and gas, including numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and in projecting future rates of production and timing of development expenditures. The future success of the Company's Exploration and Production and Gathering segments depends on its ability to develop additional oil and gas reserves that are economically recoverable, and its failure to do so may reduce the Company's earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. The Company's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, geology, and other factors. Drilling for oil and gas can be unprofitable, not only from non-productive wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements, including completion of environmental impact analyses and compliance with other environmental laws and regulations, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells is significant and often uncertain, and new wells may not be productive or the Company may not recover all or any portion of its investment. Production can also be delayed or made uneconomic if there is insufficient gathering, processing and transportation capacity available at an economic price to get that production to a location where it can be profitably sold. Without continued successful exploitation or acquisition activities, the Company's reserves and revenues will decline as a result of its current reserves being depleted by production. The Company cannot make assurances that it will be able to find or acquire additional reserves at acceptable costs.

REGULATORY RISKS

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

The Company's businesses are subject to regulation under a wide variety of federal and state laws, regulations and policies. Existing statutes and regulations, including current tax rates, may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company, which may increase the Company's costs, require refunds to customers or affect its business in ways that the Company cannot predict. Administrative agencies may apply existing laws and regulations in unanticipated, inconsistent or legally unsupportable ways, making it difficult to develop and complete projects, and harming the economic climate generally.

Various aspects of the Company's operations are subject to regulation by a variety of federal and state agencies with respect to permitting and environmental requirements. In some areas, the Company's operations may also be subject to locally adopted ordinances. Administrative proceedings or increased regulation by these agencies could lead to operational delays or restrictions and increased expense for one or more of the Company's subsidiaries.

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

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. Pursuant to the petition of a customer or state commission, or on the FERC's own initiative, the FERC has the authority to investigate whether Supply Corporation's and Empire's rates are still "just and reasonable" as required by the NGA, and if not, to adjust those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to adjust the rates it charges its gas transportation and/or storage customers, or if either Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease. In addition, the FERC exercises jurisdiction over the construction and operation of interstate gas transmission facilities and also possesses significant penalty authority with respect to violations of the laws and regulations it administers.

The operations of Distribution Corporation are subject to the jurisdiction of the NYPSC, the PaPUC and, with respect to certain transactions, the FERC. The NYPSC and the PaPUC, among other things, approve the rates that Distribution Corporation may charge to its utility customers. Those approved rates also impact the returns that Distribution Corporation may earn on the assets that are dedicated to those operations. If Distribution Corporation is unable to obtain approval from these regulators for the rates it is requesting to charge utility customers, particularly when necessary to cover increased costs, earnings may decrease.

Environmental regulation significantly affects the Company's business.

The Company's business operations are subject to federal, state, and local laws and regulations relating to environmental protection including obtaining and complying with permits, leases, approvals, consents and certifications from various governmental and permit authorities. These laws and regulations concern the generation, storage, transportation, disposal, emission or discharge of pollutants, contaminants, hazardous substances and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. For example, currently applicable environmental laws and regulations restrict the types, quantities and concentrations of materials that can be released into the environment in connection with regulated activities, limit or prohibit activities in certain protected areas, and may require the Company to investigate and/or remediate contamination at certain current and former properties regardless of whether such contamination resulted from the Company's actions or whether such actions were in compliance with applicable laws and regulations at the time they were taken. Moreover, spills or releases of regulated substances or the discovery of currently unknown contamination could expose the Company to material losses, expenditures and environmental, health and safety liabilities. Such liabilities could include penalties, sanctions or claims for damages to persons, property or natural resources brought on behalf of the government or private litigants that could cause the Company to incur substantial costs or uninsured losses.

Costs of compliance and liabilities could negatively affect the Company's results of operations, financial condition and cash flows. In addition, compliance with environmental laws, regulations or permit conditions could require unexpected capital expenditures at the Company's facilities, temporarily shut down the Company's facilities or delay or cause the cancellation of expansion projects or oil and gas drilling activities. Because the costs of such compliance are significant, additional regulation could negatively affect the Company's business.

Increased regulation of exploration and production activities, including hydraulic fracturing, could adversely impact the Company.

Due to the Marcellus and Utica Shale gas plays in the northeast United States, together with the fiscal difficulties faced by state agencies in Pennsylvania, various state legislative and regulatory initiatives regarding the exploration and production business have been proposed or adopted. These initiatives include potential new or updated statutes and regulations governing the drilling, casing, cementing, testing, abandonment and monitoring of wells, the protection of water supplies and restrictions on water use and water rights, hydraulic fracturing operations, surface owners' rights and damage compensation, the spacing of wells, use and disposal

of potentially hazardous materials, and environmental and safety issues regarding gas pipelines. New permitting fees and/or severance taxes for oil and gas production are also possible. Additionally, legislative initiatives in the U.S. Congress and regulatory studies, proceedings or rule-making initiatives at federal, state or local agencies focused on the hydraulic fracturing process, the use of underground injection control wells for produced water disposal, and related operations could result in operational delays or prohibitions and/or additional permitting, compliance, reporting and disclosure requirements, which could lead to increased operating costs and increased risks of litigation for the Company.

The Company could be adversely affected by the disallowance of purchased gas costs incurred by the Utility segment.

Tariff rate schedules in each of the Utility segment's service territories contain purchased gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased gas. Assuming those rate adjustments are granted, increases in the cost of purchased gas have no direct impact on profit margins. Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased gas. There is a risk of disallowance of full recovery of these costs if regulators determine that Distribution Corporation was imprudent in making its gas purchases. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings.

GENERAL RISKS

The Company's credit ratings may not reflect all the risks of an investment in its securities.

The Company's credit ratings are an independent assessment of its ability to pay its obligations. Consequently, real or anticipated changes in the Company's credit ratings will generally affect the market value of the specific debt instruments that are rated, as well as the market value of the Company's common stock. The Company's credit ratings, however, may not reflect the potential impact on the value of its common stock of risks related to structural, market or other factors discussed in this Form 10-K.

The increasing costs of certain employee and retiree benefits could adversely affect the Company's results.

The Company's earnings and cash flow may be impacted by the amount of income or expense it expends or records for employee benefit plans. This is particularly true for pension and other post-retirement benefit plans, which are dependent on actual plan asset returns and factors used to determine the value and current costs of plan benefit obligations. In addition, if medical costs rise at a rate faster than the general inflation rate, the Company might not be able to mitigate the rising costs of medical benefits. Increases to the costs of pension, other post-retirement and medical benefits could have an adverse effect on the Company's financial results.

Significant shareholders or potential shareholders may attempt to effect changes at the Company or acquire control over the Company, which could adversely affect the Company's results of operations and financial condition.

Shareholders of the Company may from time to time engage in proxy solicitations, advance shareholder proposals or otherwise attempt to effect changes or acquire control over the Company. Campaigns by shareholders to effect changes at publicly traded companies are sometimes led by investors seeking to increase short-term shareholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. Additionally, activist shareholders may submit proposals to promote an environmental, social or governance position. Responding to proxy contests and other actions by activist shareholders can be costly and time-consuming, disrupting the Company's operations and diverting the attention of the Company's Board of Directors and senior management from the pursuit of business strategies. As a result, shareholder campaigns could adversely affect the Company's results of operations and financial condition.

Item 1B *Unresolved Staff Comments*

None.

Item 2 *Properties*

General Information on Facilities

The net investment of the Company in property, plant and equipment was \$6.0 billion at September 30, 2020. The Exploration and Production segment constitutes 30.7% of this investment, and is primarily located in the Appalachian region of the United States and in California. Approximately 55.9% of the Company's investment in net property, plant and equipment was in the Utility and Pipeline and Storage segments, whose operations are located primarily in western and central New York and western Pennsylvania. The Gathering segment constitutes 13.3% of the Company's investment in net property, plant and equipment, and is located in northwestern Pennsylvania. The remaining 0.1% of the Company's net investment in property, plant and equipment falls within All Other and Corporate operations. During the past five years, the Company has made significant additions to property, plant and equipment in order to expand its exploration and production and gathering operations in the Appalachian region of the United States and to expand and improve transmission and distribution facilities for customers in New York and Pennsylvania. Net property, plant and equipment has increased \$666 million, or 12.5%, since September 30, 2015. The five year increase is net of impairments of oil and gas producing properties recorded in 2016 and 2020 (\$948 million and \$449 million, respectively). It is also net of \$53.4 million of timber assets that were reclassified as Assets Held for Sale at September 30, 2020.

The Exploration and Production segment had a net investment in property, plant and equipment of \$1.8 billion at September 30, 2020.

The Pipeline and Storage segment had a net investment of \$1.8 billion in property, plant and equipment at September 30, 2020. Transmission pipeline represents 36% of this segment's total net investment and includes 2,265 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 15% of this segment's total net investment and consist of 30 storage fields operating at a combined working gas level of 77.2 Bcf, three of which are jointly owned and operated with other interstate gas pipeline companies, and 389 miles of pipeline. Net investment in storage facilities includes \$82.8 million of gas stored underground-noncurrent, representing the cost of the gas utilized to maintain pressure levels for normal operating purposes as well as gas maintained for system balancing and other purposes, including that needed for no-notice transportation service. The Pipeline and Storage segment has 33 compressor stations with 227,356 installed horsepower that represent 31% of this segment's total net investment in property, plant and equipment.

The Pipeline and Storage segments' facilities provided the capacity to meet Supply Corporation's 2020 peak day sendout for transportation service of 1,935 MMcf, which occurred on February 14, 2020. Withdrawals from storage of 592.2 MMcf provided approximately 31% of the requirements on that day.

The Gathering segment had a net investment of \$0.8 billion in property, plant and equipment at September 30, 2020. Gathering lines and related compressor stations represent substantially all of this segment's total net investment, including 333 miles of pipelines utilized to move Appalachian production (including Marcellus and Utica shales) to various transmission pipeline receipt points. The Gathering segment has 23 compressor stations with 118,800 installed horsepower.

The Utility segment had a net investment in property, plant and equipment of \$1.6 billion at September 30, 2020. The net investment in its gas distribution network (including 14,972 miles of distribution pipeline) and its service connections to customers represent approximately 49% and 32%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2020.

Company maps are included in Exhibit 99.2 of this Form 10-K and are incorporated herein by reference.

Exploration and Production Activities

The Company is engaged in the exploration for and the development of natural gas and oil reserves in the Appalachian region of the United States and in California. The Company's development activities in the Appalachian region are focused primarily in the Marcellus and Utica shales. Further discussion of oil and gas producing activities is included in Item 8, Note O — Supplementary Information for Oil and Gas Producing Activities. Note O sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2020, 2019 and 2018 reserves shown in Note O are valued using 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 reserves were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Note O discusses the qualifications of the Company's reservoir engineers, internal controls over the reserve estimation process and audit of the reserve estimates and changes in proved developed and undeveloped oil and natural gas reserves year over year.

Seneca's proved developed and undeveloped natural gas reserves increased from 2,950 Bcf at September 30, 2019 to 3,325 Bcf at September 30, 2020. This increase is attributed to extensions and discoveries of 7 Bcf and acquisitions of 684 Bcf partially offset by downward revisions of 88 Bcf and production of 227 Bcf. Of the total net downward gas revisions of 88 Bcf, 8 Bcf were a result of negative price-related revisions and 179 Bcf were from 17 Pennsylvania PUD locations (two in the Marcellus Shale and 15 in the Utica Shale) removed due to the Company having no near term plans to develop these reserves. These are offset in part by upward revisions of 48 Bcf for five PUD locations added back to proved reserves in 2020 (after removing one in 2016 and four in 2017 due to scheduling delays beyond five year rule expirations) and 51 Bcf due to positive performance improvements on producing wells combined with longer laterals on certain wells.

Seneca's proved developed and undeveloped oil reserves decreased from 24,873 Mbbl at September 30, 2019 to 22,100 Mbbl at September 30, 2020. The decrease of 2,773 Mbbl is attributed to production of 2,348 Mbbl and downward revisions of previous estimates of 713 Mbbl, partially offset by extensions and discoveries of 288 Mbbl, primarily occurring in the West Coast region. Downward revisions were mainly a result of lower oil prices of 1,818 Mbbl partially offset by positive revisions of 1,105 Mbbl, which were a combination of 688 Mbbl due to operational cost efficiencies and 417 Mbbl due to field performance.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 3,099 Bcfe at September 30, 2019 to 3,458 Bcfe at September 30, 2020. This increase is attributed to acquisitions of 684 Bcfe and extensions and discoveries of 9 Bcfe, partially offset by production of 241 Bcfe and downward revisions of previous estimates of 93 Bcfe.

Seneca's proved developed and undeveloped natural gas reserves increased from 2,357 Bcf at September 30, 2018 to 2,950 Bcf at September 30, 2019. This increase was attributed to extensions and discoveries of 687 Bcf and net upward revisions of previous estimates of 104 Bcf, partially offset by production of 198 Bcf. Of the total net upward gas revisions of 104 Bcf, 152 Bcf were a result of positive revisions due to performance improvements and 7 Bcf in upward revisions for one PUD location added back to proved reserves, partially offset by 55 Bcf for six PUD locations that were removed.

Seneca's proved developed and undeveloped oil reserves decreased from 27,663 Mbbl at September 30, 2018 to 24,873 Mbbl at September 30, 2019. The decrease was attributed to production of 2,323 Mbbl, primarily occurring in the West Coast region, and downward revisions of previous estimates of 1,254 Mbbl, partially offset by extensions and discoveries of 787 Mbbl. Downward revisions of 1,254 Mbbl were largely a result of reduced performance from producing wells mainly at Seneca's Midway Sunset field.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 2,523 Bcfe at September 30, 2018 to 3,099 Bcfe at September 30, 2019. This increase was attributed to extensions and discoveries of 692 Bcfe and upward revisions of previous estimates of 96 Bcfe, partially offset by production of 212 Bcfe.

At September 30, 2020, the Company's Exploration and Production segment had delivery commitments for production of 2,327 Bcfe (mostly natural gas as commitments for crude oil were insignificant). The Company expects to meet those commitments through the future development of reserves that are currently classified as proved reserves and future extensions and discoveries.

The following is a summary of certain oil and gas information taken from Seneca's records. All monetary amounts are expressed in U.S. dollars.

Production

	For The Year Ended September 30		
	2020	2019	2018
United States			
<u>Appalachian Region</u>			
Average Sales Price per Mcf of Gas	\$ 1.75 (1)	\$ 2.40 (1)	\$ 2.36 (1)
Average Sales Price per Barrel of Oil	\$ 45.69	\$ 57.14	\$ 57.76
Average Sales Price per Mcf of Gas (after hedging)	\$ 2.05	\$ 2.41	\$ 2.49
Average Sales Price per Barrel of Oil (after hedging)	\$ 45.69	\$ 57.14	\$ 57.76
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	\$ 0.68 (1)	\$ 0.67 (1)	\$ 0.69 (1)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	616 (1)	537 (1)	440 (1)
<u>West Coast Region</u>			
Average Sales Price per Mcf of Gas	\$ 3.82	\$ 5.15	\$ 4.86
Average Sales Price per Barrel of Oil	\$ 45.94	\$ 64.18	\$ 66.39
Average Sales Price per Mcf of Gas (after hedging)	\$ 3.82	\$ 5.15	\$ 4.86
Average Sales Price per Barrel of Oil (after hedging)	\$ 56.97	\$ 61.66	\$ 58.66
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	\$ 3.14	\$ 3.47	\$ 2.98
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	44	43	48
Total Company			
Average Sales Price per Mcf of Gas	\$ 1.77	\$ 2.43	\$ 2.40
Average Sales Price per Barrel of Oil	\$ 45.94	\$ 64.17	\$ 66.38
Average Sales Price per Mcf of Gas (after hedging)	\$ 2.07	\$ 2.44	\$ 2.52
Average Sales Price per Barrel of Oil (after hedging)	\$ 56.96	\$ 61.65	\$ 58.66
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	\$ 0.84	\$ 0.88	\$ 0.91
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	660	580	488

- (1) Average sales prices per Mcf of gas reflect sales of gas in the Marcellus and Utica Shale fields. The Marcellus Shale fields (which exceed 15% of total reserves at September 30, 2020, 2019 and 2018) contributed 463 MMcfe, 447 MMcfe and 412 MMcfe of daily production in 2020, 2019 and 2018, respectively. The average lifting costs (per Mcfe) were \$0.70 in 2020, \$0.68 in 2019 and \$0.69 in 2018. The Utica Shale fields (which exceed 15% of total reserves at September 30, 2020, 2019 and 2018) contributed 151 MMcfe, 88 MMcfe and 26 MMcfe of daily production in 2020, 2019 and 2018, respectively. The average lifting costs (per Mcfe) were \$0.62 in 2020, \$0.63 in 2019 and \$0.64 in 2018.

Productive Wells

	Appalachian Region		West Coast Region		Total Company	
	Gas	Oil	Gas	Oil	Gas	Oil
At September 30, 2020						
Productive Wells — Gross	881	—	—	1,865	881	1,865
Productive Wells — Net	768	—	—	1,831	768	1,831

Developed and Undeveloped Acreage

At September 30, 2020	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
— Gross	659,046	17,042	676,088
— Net	649,296	15,409	664,705
Undeveloped Acreage			
— Gross	711,022	—	711,022
— Net	664,336	—	664,336
Total Developed and Undeveloped Acreage			
— Gross	1,370,068	17,042	1,387,110
— Net	1,313,632 (1)	15,409	1,329,041

- (1) Of the 1,313,632 Total Developed and Undeveloped Net Acreage in the Appalachian region as of September 30, 2020, there are a total of 1,243,444 net acres in Pennsylvania. Of the 1,243,444 total net acres in Pennsylvania, shale development in the Marcellus, Utica or Geneseo shales has occurred on approximately 101,990 net acres, or 8.2% of Seneca's total net acres in Pennsylvania. Developed Acreage in the table reflects previous development activities in the Upper Devonian formation, but does not include the potential for development beneath this formation in areas of previous development, which includes the Marcellus, Utica and Geneseo shales.

As of September 30, 2020, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 967 acres in 2021 (695 net acres), 4,882 acres in 2022 (4,403 net acres), 2,973 acres in 2023 (2,648 net acres) and 209,665 acres thereafter (205,344 net acres). The remaining 492,535 gross acres (451,246 net acres) represent non-expiring oil and gas rights owned by the Company. Of the acreage that is currently scheduled to expire in 2021, 2022 and 2023, Seneca has 4.2 Bcf of associated proved undeveloped gas reserves. As a part of its management approved development plan, Seneca generally commences development of these reserves prior to the expiration of the leases and/or proactively extends/renews these leases.

Drilling Activity

For the Year Ended September 30	Productive			Dry		
	2020	2019	2018	2020	2019	2018
United States						
<u>Appalachian Region</u>						
Net Wells Completed						
— Exploratory	—	—	4.00	1.00	—	—
— Development(1)	39.84	40.00	41.40	6.50	7.00	9.00
<u>West Coast Region</u>						
Net Wells Completed						
— Exploratory	—	—	—	—	—	—
— Development	34.00	44.00	15.00	—	1.00	—
Total Company						
Net Wells Completed						
— Exploratory	—	—	4.00	1.00	—	—
— Development	73.84	84.00	56.40	6.50	8.00	9.00

- (1) Fiscal 2020 and 2019 Appalachian region dry wells include 4.5 and 3 net wells, respectively, drilled in 2011 that were never completed under a joint venture in which the Company was the nonoperator. The Company became the operator of the properties in 2017 and plugged and abandoned the wells in 2020 and 2019 after the Company determined it would not continue development activities. The remaining 2

dry wells in fiscal 2020, 4 dry wells in 2019 and 9 dry wells in 2018 relate to plugged and abandoned well locations where preparatory top-hole drilling operations had commenced but further development activities (e.g., vertical and horizontal drilling, hydraulic fracturing, etc.) did not proceed as a result of changes to the Company's development plans.

Present Activities

At September 30, 2020	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
— Gross	56.00	—	56.00
— Net	49.00	—	49.00

(1) Includes wells awaiting completion.

Item 3 *Legal Proceedings*

For a discussion of various environmental and other matters, refer to Part II, Item 7, MD&A and Item 8 at Note L — Commitments and Contingencies.

For a discussion of certain rate matters involving the NYPSC, refer to Part II, Item 7, MD&A of this report under the heading "Other Matters - Rate Matters."

Item 4 *Mine Safety Disclosures*

Not Applicable.

PART II

Item 5 *Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

At September 30, 2020, there were 9,993 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange under the trading symbol "NFG". Information regarding the market for the Company's common equity and related stockholder matters appears under Item 12 at Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and Item 8 at Note H — Capitalization and Short-Term Borrowings.

On July 1, 2020, the Company issued a total of 10,620 unregistered shares of Company common stock to the ten non-employee directors of the Company then serving on the Board of Directors of the Company, consisting of 1,062 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 September 30, 2020. 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

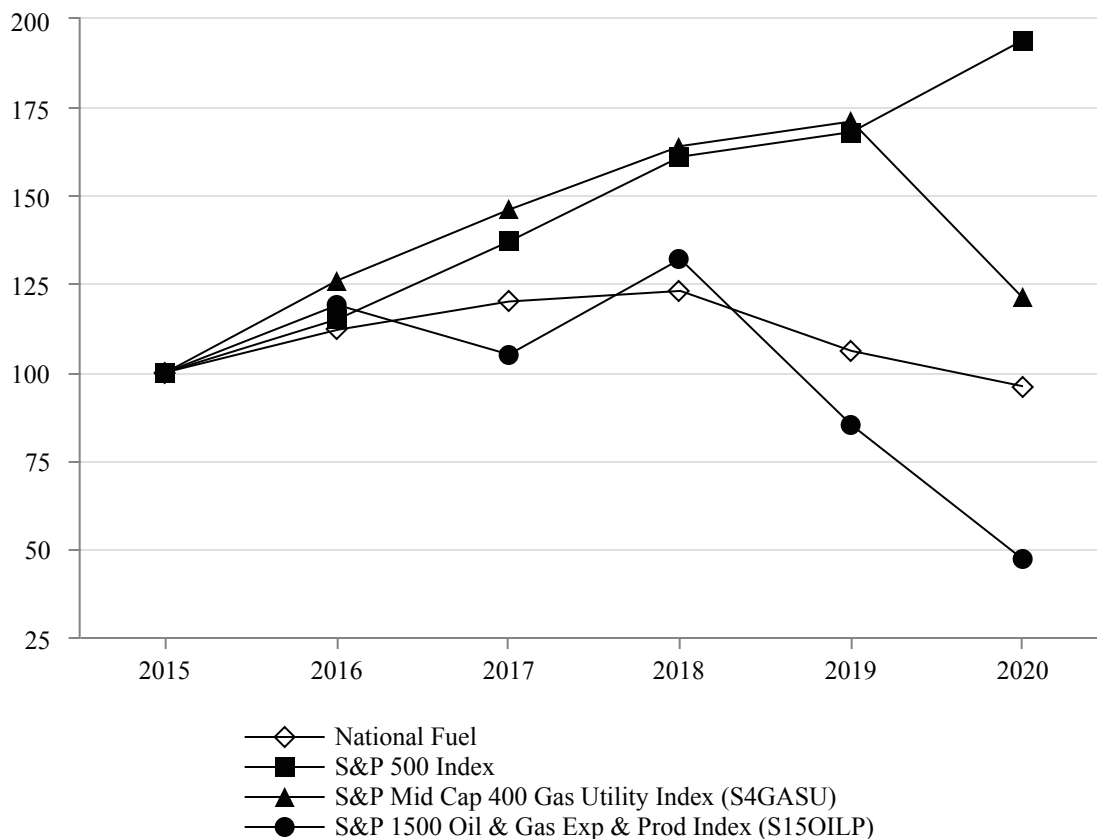
<u>Period</u>	<u>Total Number of Shares Purchased(a)</u>	<u>Average Price Paid per Share</u>	<u>Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs</u>	<u>Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs(b)</u>
July 1-31, 2020	14,195	\$ 39.77	—	6,971,019
Aug. 1-31, 2020	13,455	\$ 44.50	—	6,971,019
Sept. 1-30, 2020	12,891	\$ 43.26	—	6,971,019
Total	<u>40,541</u>	<u>\$ 42.45</u>	—	6,971,019

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- (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 September 30, 2020, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 40,541 shares purchased other than through a publicly announced share repurchase program, 40,265 were purchased for the Company's 401(k) plans and 276 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.

Performance Graph

The following graph compares the Company's common stock performance with the performance of the S&P 500 Index, the S&P Mid Cap 400 Gas Utility Index and the S&P 1500 Oil & Gas Exploration & Production Index for the period September 30, 2015 through September 30, 2020. The graph assumes that the value of the investment in the Company's common stock and in each index was \$100 on September 30, 2015 and that all dividends were reinvested.

Comparison of Five-Year Cumulative Total Returns Fiscal Years 2016 - 2020



	2015	2016	2017	2018	2019	2020
National Fuel	\$100	\$112	\$120	\$123	\$106	\$96
S&P 500 Index	\$100	\$115	\$137	\$161	\$168	\$194
S&P Mid Cap 400 Gas Utility Index (S4GASU) ..	\$100	\$126	\$146	\$164	\$171	\$121
S&P 1500 Oil & Gas Exp & Prod Index (S15OILP)	\$100	\$119	\$105	\$132	\$85	\$47

Source: Bloomberg

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

Item 6 Selected Financial Data

	Year Ended September 30				
	2020	2019	2018	2017	2016
(Thousands, except per share amounts and number of registered shareholders)					
Summary of Operations					
Operating Revenues:					
Utility and Energy Marketing Revenues	\$ 728,336	\$ 860,985	\$ 812,474	\$ 755,485	\$ 624,602
Exploration and Production and Other Revenues	611,885	636,528	569,808	617,666	611,766
Pipeline and Storage and Gathering Revenues	206,070	195,819	210,386	206,730	216,048
	<u>1,546,291</u>	<u>1,693,332</u>	<u>1,592,668</u>	<u>1,579,881</u>	<u>1,452,416</u>
Operating Expenses:					
Purchased Gas	233,890	386,265	337,822	275,254	147,982
Operation and Maintenance:					
Utility and Energy Marketing	181,051	171,472	168,885	169,731	192,512
Exploration and Production and Other	148,856	147,457	139,546	141,010	160,201
Pipeline and Storage and Gathering	108,640	111,783	101,338	90,918	88,801
Property, Franchise and Other Taxes	88,400	88,886	84,393	84,995	81,714
Depreciation, Depletion and Amortization	306,158	275,660	240,961	224,195	249,417
Impairment of Oil and Gas Producing Properties	449,438	—	—	—	948,307
	<u>1,516,433</u>	<u>1,181,523</u>	<u>1,072,945</u>	<u>986,103</u>	<u>1,868,934</u>
Operating Income (Loss)	29,858	511,809	519,723	593,778	(416,518)
Other Income (Expense):					
Other Income (Deductions)	(17,814)	(15,542)	(21,174)	(29,777)	14,055
Interest Expense on Long-Term Debt	(110,012)	(101,614)	(110,946)	(116,471)	(117,347)
Other Interest Expense	(7,065)	(5,142)	(3,576)	(3,366)	(3,697)
Income (Loss) Before Income Taxes	(105,033)	389,511	384,027	444,164	(523,507)
Income Tax Expense (Benefit)	18,739	85,221	(7,494)	160,682	(232,549)
Net Income (Loss) Available for Common Stock	<u>\$ (123,772)</u>	<u>\$ 304,290</u>	<u>\$ 391,521</u>	<u>\$ 283,482</u>	<u>\$ (290,958)</u>
Per Common Share Data					
Basic Earnings (Loss) per Common Share	\$ (1.41)	\$ 3.53	\$ 4.56	\$ 3.32	\$ (3.43)
Diluted Earnings (Loss) per Common Share	\$ (1.41)	\$ 3.51	\$ 4.53	\$ 3.30	\$ (3.43)
Dividends Declared	\$ 1.76	\$ 1.72	\$ 1.68	\$ 1.64	\$ 1.60
Dividends Paid	\$ 1.75	\$ 1.71	\$ 1.67	\$ 1.63	\$ 1.59
Dividend Rate at Year-End	\$ 1.78	\$ 1.74	\$ 1.70	\$ 1.66	\$ 1.62
At September 30:					
Number of Registered Shareholders	<u>9,993</u>	<u>10,359</u>	<u>10,751</u>	<u>11,211</u>	<u>11,751</u>

	Year Ended September 30				
	2020	2019	2018	2017	2016
(Thousands, except per share amounts and number of registered shareholders)					
Net Property, Plant and Equipment					
Exploration and Production	\$1,840,863	\$1,731,862	\$1,370,340	\$1,196,521	\$1,083,804
Pipeline and Storage	1,803,604	1,683,038	1,583,699	1,524,197	1,463,541
Gathering	799,777	523,219	493,694	455,701	439,660
Utility	1,551,803	1,512,983	1,469,645	1,435,414	1,403,286
All Other	1,143	56,245	57,562	59,463	60,799
Corporate and Intersegment Eliminations	877	2,163	2,203	2,778	3,392
Total Net Plant	<u>\$5,998,067</u>	<u>\$5,509,510</u>	<u>\$4,977,143</u>	<u>\$4,674,074</u>	<u>\$4,454,482</u>
Total Assets	<u><u>\$6,964,935</u></u>	<u><u>\$6,462,157</u></u>	<u><u>\$6,036,486</u></u>	<u><u>\$6,103,320</u></u>	<u><u>\$5,636,387</u></u>
Capitalization					
Comprehensive Shareholders' Equity . . .	\$1,971,986	\$2,139,025	\$1,937,330	\$1,703,735	\$1,527,004
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,629,576	2,133,718	2,131,365	2,083,681	2,086,252
Total Capitalization	<u><u>\$4,601,562</u></u>	<u><u>\$4,272,743</u></u>	<u><u>\$4,068,695</u></u>	<u><u>\$3,787,416</u></u>	<u><u>\$3,613,256</u></u>

Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations*

OVERVIEW

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 producers in the Appalachian basin. The Company also develops and produces oil reserves, primarily in California. The Company reports financial results for four business segments: Exploration and Production, Pipeline and Storage, Gathering, and Utility.

Corporate Responsibility

The Board of Directors and management recognize that the long-term interests of stockholders are served by considering the interests of customers, employees and the communities in which the Company operates. The Board retains risk oversight and general oversight of corporate responsibility, including environmental, social and governance ("ESG") concerns, and any related health and safety issues that might arise from the Company's operations. An important aspect of that oversight is the Enterprise Risk Management process, which informs the strategic planning process. Management reports quarterly to the Board on significant risk categories. The Board's Nominating/Corporate Governance Committee oversees and provides guidance concerning the Company's practices and reporting with respect to corporate responsibility and ESG factors that are of significance to the Company and its stakeholders, and may also make recommendations to the Board regarding ESG initiatives and strategies, including the Company's progress on integrating ESG factors into business strategy and decision-making.

The Board has directed management to integrate corporate responsibility concerns into business strategy and decision-making throughout the organization. The Company takes very seriously its role as a corporate citizen and remains committed to the welfare of the areas in which it operates, which is reflected in the Company's six "Guiding Principles" (Safety, Environmental Stewardship, Community, Innovation, Satisfaction and Transparency). These principles reflect and promote a culture that is committed to the tenets of corporate responsibility.

The Company recognizes the ongoing developments and risks surrounding climate change, as well as corresponding opportunities. The Board and management consider these risks and opportunities in their strategic and capital spending decision process. Further, since the Company operates an integrated business with assets being utilized for, and benefiting from, the production, transportation and consumption of natural gas, the Board and management consider the impact of climate change developments on future natural gas usage.

The Company believes that natural gas will remain a significant component of the global and national energy complex. The U.S. Energy Information Administration (EIA) provides relevant data and projections in this regard. The EIA's 2020 International Energy Outlook projects that worldwide natural gas consumption will increase by more than 40% through 2050. In addition, natural gas is a clean form of energy when compared to other fossil fuels such as oil or coal with respect to greenhouse gas emissions. In its 2019 New York State Greenhouse Gas Inventory Report, the New York State Energy Research and Development Authority noted that from 1990 to 2016, "emissions from electricity generated in-State dropped 56% during this . . . period, acting as a major driver of New York State's decreasing GHG emissions. This drop is due in part to the significant decrease in the burning of coal and petroleum products in the electricity generation sector. Emissions from residential, commercial, and industrial buildings also decreased, showing a reduction of approximately 23% from 1990 to 2016." The Company believes that expanded use of natural gas in those sectors significantly contributed to these emissions reductions.

The Company also recognizes the important role of ongoing system modernization and efficiency in reducing greenhouse gas emissions. The Company's replacement of older natural gas infrastructure is expected to continue to reduce leaks, enhance system safety, and directly lower greenhouse gas emissions. In its Utility segment, the Company directs capital spending to infrastructure replacement and to other investments (such as the purchase of vehicles and equipment necessary for that activity) that support its statutory obligation to provide safe and reliable service. As a result of system modernization, the Utility segment, from 2012 to 2019, has seen a 24.7% reduction in greenhouse gas emissions, primarily methane, reported to the EPA under Subpart W of 40 CFR Part 98. In its Pipeline and Storage businesses, a significant portion of the capital budget is spent on modernization, including leveraging expansion projects to also upgrade existing infrastructure. In its Exploration and Production segment, the Company has implemented initiatives throughout the drilling process that are aimed at minimizing greenhouse gas emissions and improving air quality, including green completion techniques and deploying leak detection technologies. Likewise, the Exploration and Production segment recognizes the importance of efficient and innovative water sourcing, handling and recycling. To assist in water management, the Company established a water logistics company, Highland Field Services, to improve its water resourcing and recycling capabilities.

The Company also works with various regulatory commissions to develop ratemaking initiatives to increase end use efficiency while reducing downside risk from demand fluctuation. In addition, in 2018, subsidiaries of the Company's Utility, Pipeline and Storage, Midstream and Exploration and Production segments all joined the EPA's Natural Gas STAR Methane Challenge Program. This voluntary program within the energy industry is designed to provide a transparent platform for utilities, pipeline and storage companies, and energy producers to make, track and communicate commitments to reduce methane emissions.

The Company recognizes the evolving landscape of international accords and federal, state and local laws and regulations regarding greenhouse gas emissions or climate change initiatives. Changing market conditions, new laws 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. The Company adjusts its approach to capital investment in response to regulatory change and believes that its long-term, returns-focused approach, along with its integrated and diversified business model make it well positioned to take advantage of potential opportunities to participate in the ongoing efforts

to decarbonize our economy. For instance, the recently completed Empire North expansion project included the Company's first electric motor driver compressor station, located in New York State, which virtually eliminates combustion emissions from the facility.

Fiscal 2020 Highlights

This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, "Results of Operations;"
3. Operating, investing and financing cash flows under the heading "Capital Resources and Liquidity;"
4. Contractual Obligations; and
5. Other Matters, including: (a) 2020 and projected 2021 funding for the Company's pension and other post-retirement benefits; (b) disclosures and tables concerning market risk sensitive instruments; (c) rate matters in the Company's New York, Pennsylvania and FERC-regulated jurisdictions; and (d) environmental matters.

The information in MD&A should be read in conjunction with the Company's financial statements in Item 8 of this report, which includes a comparison of our Results of Operations and Capital Resources and Liquidity for fiscal 2020 and fiscal 2019. For a discussion of the Company's earnings, refer to the Results of Operations section below. A discussion of changes in the Company's results of operations from fiscal 2018 to fiscal 2019 has been omitted from this Form 10-K, but may be found in Item 7, MD&A, of the Company's Form 10-K for the fiscal year ended September 30, 2019, filed with the SEC on November 15, 2019.

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 Part I, Item 1A, Risk Factors, under Operational Risks for a more complete discussion of the risks to the Company associated with the COVID-19 pandemic. From an economic perspective, the pandemic contributed to lower demand for natural gas and oil during the second half of fiscal 2020, which in turn depressed prices for those commodities, resulting in lower revenues in the Company's Exploration and Production segment. As government mandated shut downs have eased to a large degree over the last few months, business activity has improved but has not returned to pre-pandemic levels. Recently, there has been an improvement in the outlook for natural gas pricing, most likely due to reduced industry-wide drilling activity stemming from the depressed prices that have existed for most of 2020. The Company's Pipeline and Storage segment has not been significantly impacted by the COVID-19 pandemic at this point. In the Company's Utility segment, as the COVID-19 pandemic continues into the winter heating season and customers are faced with seasonally higher natural gas prices and higher usage, the financial strains on businesses and individuals could have an impact on their ability to pay their bills, which could lead to an increase in customer non-payments. To date, however, the Utility segment has not experienced any meaningful change in the rate at which its customers pay their bills.

One of the steps taken by the federal government to help companies during the COVID-19 pandemic was the passage of the CARES Act on March 27, 2020. The CARES Act, among other things, includes provisions relating to alternative minimum tax (AMT) credit refunds, refundable payroll tax credits, deferment of employer side social security payments, net operating loss carryback periods, and modifications to the net interest deduction limitation. The Company filed for the acceleration of the remaining AMT credit refunds (under CARES) of \$42.5 million, which were received in June 2020. The Company has deferred employer side social security payments to the federal government and continues to evaluate other elements of the CARES Act for potential adoption by the Company.

Given the COVID-19 pandemic and other economic factors, the Company experienced low natural gas and oil prices for most of fiscal 2020. 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. The Company recorded cumulative impairment charges under the ceiling test during 2020

of \$449.4 million (\$326.3 million after-tax). The Company could potentially record non-cash impairments in future quarters depending on the commodity price environment. Given the significant impairments recorded during 2020, under its existing indenture covenants, the Company is precluded from issuing incremental long-term unsecured indebtedness for a period beginning in January 2021 and expected to extend for several quarters in fiscal 2021. Depending on the magnitude of any future impairments, it is possible that the Company's indenture covenants could restrict the Company's ability to issue incremental long-term unsecured indebtedness beyond that period. However, the Company expects that it could borrow under its credit facilities and the 1974 indenture would not preclude the Company from issuing new indebtedness to replace maturing debt. Please refer to the Critical Accounting Estimates section below for a sensitivity analysis concerning commodity price changes.

Given the current low commodity price environment, the Company's Exploration and Production segment moved from a 3-rig development program to a 2-rig development program in the Appalachian region in January 2020, and subsequently moved to a single-rig development program in June 2020. In advance of the expected late calendar 2021 online date for Seneca's capacity on the Leidy South Project, and in response to the current improvement of natural gas futures prices for the Company's 2022 fiscal year, the Company now expects to add a second horizontal drilling rig in the Appalachian region in early calendar 2021. Although first production from the second rig is not expected until early fiscal 2022, Seneca anticipates an increase in natural gas production in fiscal 2021, partially driven by the Company's recent acquisition of proved developed producing reserves described below. The Company's Exploration and Production segment continues to grow, as evidenced by a 12% growth in proved reserves from the prior year to a total of 3,458 Bcfe at September 30, 2020.

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, including transaction costs. As part of the transaction, the Company acquired over 400,000 net acres in Appalachia, including approximately 200,000 net acres in Tioga County, Pennsylvania. The proved developed natural gas reserves associated with this acquisition amounted to 684 Bcf. In addition, the Company acquired gathering pipelines and related compression, water pipelines, and associated water handling infrastructure, all of which support the acquired Tioga County production operations. These gathering facilities are interconnected with various interstate pipelines, including the Company's Empire pipeline system, with the potential to tie into the Company's existing Covington gathering system. Post closing, the Company has integrated the assets into its existing operations in Tioga County, which has resulted in cost synergies. This will drive operating cost synergies in both the Exploration and Production and the Gathering segments. The acquisition was financed with a combination of debt and equity, as discussed in the paragraphs that follow. The purchase and sale agreement with Shell was structured, in part, as a reverse like-kind exchange pursuant to Section 1031 of the Internal Revenue Code, as amended ("Reverse 1031 Exchange").

On August 5, 2020, the Company entered into a purchase and sale agreement to sell substantially all timber and other assets in Pennsylvania to Lyme Emporium Highlands III LLC and Lyme Allegheny Land Company II LLC for \$115.7 million, subject to closing adjustments. The transaction is expected to close before the end of calendar 2020. The Company intends to use the proceeds from this sale to complete the Reverse 1031 Exchange discussed above.

In June 2020, the Company issued \$500.0 million of 5.50% notes due January 15, 2026. The proceeds of the 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. In June 2020, the Company also 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. The proceeds from this issuance were used to fund a portion of the purchase price of the aforementioned acquisition of Shell's upstream assets and midstream gathering assets in Pennsylvania.

In May 2020, the Company entered into a 364-Day credit facility with a syndicate of 10 banks, all of which are also lenders under the Company's existing \$750.0 million multi-year credit facility. The 364-Day credit facility provides an additional \$200.0 million unsecured committed revolving credit facility.

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

The Company continues to pursue development projects to expand its Pipeline and Storage segment. The Company is monitoring the impacts of the COVID-19 pandemic on its supply chains and development projects in this segment. To date, the COVID-19 pandemic has not had a material impact on the target in-service dates of these development projects. However, the unpredictable extent and duration of the outbreak, and the government imposition of certain significant restrictions associated therewith, could delay receipt of necessary equipment or delay construction. The Company will continue to monitor this rapidly evolving situation and mitigate where possible. One project on Empire's system, referred to as the Empire North Project, 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 TGP 200 Line. In July 2020, Empire placed the Jackson compressor station in service to begin partial, interim service. The remaining Empire North facilities were placed in-service on September 15, 2020. The final project cost is estimated to be \$129 million. 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. The FM100 Project has a target in-service date in late calendar 2021 and a preliminary cost estimate of approximately \$280 million. These and other projects are discussed in more detail in the Capital Resources and Liquidity section that follows.

From a rate perspective, Supply Corporation filed a Section 4 rate case on July 31, 2019. The new rates became effective on February 1, 2020 under a proposed settlement, and the settlement was approved on June 1, 2020. This increased earnings in 2020 by \$14.9 million. For further discussion of Supply Corporation's rate matters, refer to the Rate Matters section below.

From a legislation 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 to 60% of 1990 levels by 2030, and to 15% of 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. In the near-term, the CLCPA establishes 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.

CRITICAL ACCOUNTING ESTIMATES

The Company has prepared its consolidated financial statements in conformity with GAAP. The preparation of these financial statements 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. In the event estimates or assumptions prove to be different from actual results, adjustments are made in subsequent periods to reflect more current information. The following is a summary of the Company's most critical accounting estimates, which are defined as those estimates whereby judgments or uncertainties could affect the application of accounting policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the Company's significant accounting policies, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

Oil and Gas Exploration and Development Costs. 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 accounting 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.

Proved reserves are estimated quantities of reserves that, based on geologic and engineering data, appear with reasonable certainty to be producible under existing economic and operating conditions. Such estimates of proved reserves are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The estimates involved in determining proved reserves are critical accounting estimates because they serve as the basis over which capitalized costs are depleted under the full cost method of accounting (on a units-of-production basis). Unproved properties are excluded from the depletion calculation until proved reserves are found or it is determined that the unproved properties are impaired. 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.

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. 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 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 (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 estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions to or subtractions from proved reserves and significant fluctuations in oil and gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment charge must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. The book value of the Company's oil and gas properties exceeded the ceiling at September 30, 2020 as well as at June 30, 2020 and March 31, 2020, resulting in cumulative impairment charges of \$449.4 million (\$326.3 million after-tax) for 2020. The 12-month average of the first day of the month price for crude oil for each month during 2020, based on posted Midway Sunset prices, was \$43.41 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2020, based on the quoted Henry Hub spot price for natural gas, was \$1.97 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 2020. 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 additional impairment that the Company would have recorded at September 30, 2020 if natural gas prices were \$0.25 per MMBtu lower than the average prices used at September 30, 2020, the additional impairment that the Company would have recorded at September 30, 2020 if crude oil prices were \$5 per Bbl lower than the average prices used at September 30, 2020, and the additional impairment that the Company would have recorded at September 30, 2020 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 September 30, 2020 (all amounts are presented after-tax). These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation, including, among others, changes in reserve quantities and future cost estimates.

Ceiling Testing Sensitivity to Commodity Price Changes

<i>(Millions)</i>	\$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	\$ 448.7	\$ 222.9	\$ 487.8
Actual Impairment Recorded at September 30, 2020 ..	183.7	183.7	183.7
Additional Impairment	<u>\$ 265.0</u>	<u>\$ 39.2</u>	<u>\$ 304.1</u>

Looking ahead, the first day of the month Midway Sunset prices for crude oil in October 2020 and November 2020 were \$36.27 per Bbl and \$33.57 per Bbl, respectively. The first day of the month Henry Hub prices for natural gas in October 2020 and November 2020 were \$1.63 per MMBtu and \$3.04 per MMBtu, respectively. While natural gas prices have significantly improved from October to November, the decline in oil prices from October to November and other factors in the ceiling test calculation, such as changes in reserve quantities and future cost estimates, may lead to additional non-cash impairments in subsequent quarters.

In accordance with the current authoritative guidance for asset retirement obligations, the Company records an asset retirement obligation for plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and capitalizes such costs in property, plant and equipment (i.e. the full cost pool). Under the current authoritative guidance for asset retirement obligations, since plugging and abandonment costs are already included in the full cost pool, the units-of-production depletion calculation excludes from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

As discussed above, the full cost method of accounting provides a ceiling to the amount of costs that can be capitalized in the full cost pool. In accordance with current authoritative guidance, the future cash outflows associated with plugging and abandoning wells are excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation.

Regulation. The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to the FASB authoritative guidance regarding accounting for certain types of regulations, and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting principles for certain types of rate-regulated activities provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item. For further discussion of the Company's regulatory assets and liabilities, refer to Item 8 at Note F — Regulatory Matters.

Pension and Other Post-Retirement Benefits. The amounts reported in the Company's financial statements related to its pension and other post-retirement benefits are determined on an actuarial basis, which uses many assumptions in the calculation of such amounts. These assumptions include the discount rate, the expected return on plan assets, the rate of compensation increase and, for other post-retirement benefits, the expected annual rate of increase in per capita cost of covered medical and prescription benefits. The Company determines the service and interest cost components of net periodic benefit cost using the spot rate approach. Under this approach, the Company uses individual spot rates along the yield curve that correspond to the timing

of each benefit payment in order to determine the discount rate. The individual spot rates along the yield curve are determined by an above mean methodology in that the coupon interest rates that are in the lower 50th percentile are excluded based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities. The expected return on plan assets assumption used by the Company reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets. Changes in actuarial assumptions and actuarial experience, including deviations between actual versus expected return on plan assets, could have a material impact on the amount of pension and post-retirement benefit costs and funding requirements experienced by the Company. However, the Company expects to recover a substantial portion of its net periodic pension and other post-retirement benefit costs attributable to employees in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorization, subject to applicable accounting requirements for rate-regulated activities, as discussed above under "Regulation."

Changes in actuarial assumptions and actuarial experience could also have an impact on the benefit obligation and the funded status related to the Company's pension and other post-retirement benefits and could impact the Company's equity. For example, the discount rate used to determine benefit obligations of the Company's other post-retirement benefits changed from 3.17% in 2019 to 2.71% in 2020. The change in the discount rate from 2019 to 2020 increased the accumulated post-retirement benefit obligation by \$25.4 million. The discount rate used to determine benefit obligations of the Retirement Plan changed from 3.15% in 2019 to 2.66% in 2020. The change in the discount rate from 2019 to 2020 increased the Retirement Plan projected benefit obligation by \$61.3 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligation and the accumulated post-retirement benefit obligation. The actual return on Retirement Plan assets for 2020 was higher than the expected return, which resulted in a \$27.3 million increase to the funded status of the Retirement Plan. The actual return on the VEBA trusts and 401(h) account assets for 2020 was higher than expected return, which resulted in a \$15.2 million increase to the funded status of the VEBA trusts and 401(h) accounts. The actual versus expected benefit payments for 2020 caused a decrease of \$3.7 million to the accumulated post-retirement benefit obligation. In addition, changes in per-capita claim costs, premiums, retiree contributions and retiree drug subsidy assumptions in order to better reflect anticipated experience based on actual experience resulted in a decrease to the accumulated post-retirement benefit obligation of \$5.2 million. In calculating the projected benefit obligation for the Retirement Plan and the accumulated post-retirement benefit obligation, the actuary takes into account the average remaining service life of active participants. The average remaining service life of active participants is 6 years for the Retirement Plan and 5 years for those eligible for other post-retirement benefits. For further discussion of the Company's pension and other post-retirement benefits, refer to Other Matters in this Item 7, which includes a discussion of funding for the current year, and to Item 8 at Note K — Retirement Plan and Other Post-Retirement Benefits.

RESULTS OF OPERATIONS

EARNINGS

2020 Compared with 2019

The Company recorded a loss of \$123.8 million in 2020 compared to earnings of \$304.3 million in 2019. The decrease in earnings is primarily the result of a loss recognized in the Exploration and Production segment. Lower earnings in the Utility segment, as well as losses in the Corporate category and All Other category, also contributed to the decrease. Higher earnings in the Pipeline and Storage segment and Gathering segment partially offset these decreases. In the discussion that follows, all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted. Earnings were impacted by the following events in 2020 and 2019:

2020 Events

- Non-cash impairment charges of \$449.4 million (\$326.3 million after tax) recorded during 2020 for the Exploration and Production segment's oil and gas producing properties.
- A deferred tax valuation allowance of \$56.8 million established during the quarter ended March 31, 2020, primarily in the Exploration and Production and Gathering segments.

2019 Event

- A \$5.0 million remeasurement of accumulated deferred income taxes as a result of the 2017 Tax Reform Act.

Earnings (Loss) by Segment

	Year Ended September 30		
	2020	2019	2018
	(Thousands)		
Exploration and Production	\$ (326,904)	\$ 111,807	\$ 180,632
Pipeline and Storage	78,860	74,011	97,246
Gathering	68,631	58,413	83,519
Utility	57,366	60,871	51,217
Total Reported Segments	(122,047)	305,102	412,614
All Other	(269)	(1,811)	261
Corporate	(1,456)	999	(21,354)
Total Consolidated	<u>\$ (123,772)</u>	<u>\$ 304,290</u>	<u>\$ 391,521</u>

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30	
	2020	2019
	(Thousands)	
Gas (after Hedging)	\$ 470,270	\$ 482,534
Oil (after Hedging)	133,712	143,224
Gas Processing Plant	2,374	3,277
Other	1,097	3,705
Operating Revenues	<u>\$ 607,453</u>	<u>\$ 632,740</u>

Production

	Year Ended September 30	
	2020	2019
Gas Production (MMcf)		
Appalachia	225,513	195,906
West Coast	1,889	1,974
Total Production	227,402	197,880
Oil Production (Mbbbl)		
Appalachia	3	3
West Coast	2,345	2,320
Total Production	2,348	2,323

Average Prices

	Year Ended September 30	
	2020	2019
Average Gas Price/Mcf		
Appalachia	\$ 1.75	\$ 2.40
West Coast	\$ 3.82	\$ 5.15
Weighted Average	\$ 1.77	\$ 2.43
Weighted Average After Hedging(1)	\$ 2.07	\$ 2.44
Average Oil Price/Barrel (Bbl)		
Appalachia	\$ 45.69	\$ 57.14
West Coast	\$ 45.94	\$ 64.18
Weighted Average	\$ 45.94	\$ 64.17
Weighted Average After Hedging(1)	\$ 56.96	\$ 61.65

(1) Refer to further discussion of hedging activities below under “Market Risk Sensitive Instruments” and in Note J — Financial Instruments in Item 8 of this report.

2020 Compared with 2019

Operating revenues for the Exploration and Production segment decreased \$25.3 million in 2020 as compared with 2019. Gas production revenue after hedging decreased \$12.3 million primarily due to a \$0.37 per Mcf decrease in the weighted average price of gas after hedging partially offset by a 29.5 Bcf increase in gas production. The increase in gas production, despite 17.1 Bcf of price-related curtailments in 2020, was largely due to new Marcellus and Utica wells completed and connected to sales in Seneca's Western and Eastern Development Areas in the Appalachian region coupled with additional production from the acquisition of Appalachian upstream assets from Royal Dutch Shell plc (Shell) on July 31, 2020. The acquisition from Shell is discussed below under Capital Resources and Liquidity. Oil production revenue after hedging decreased \$9.5 million primarily due to a \$4.69 per Bbl decrease in the weighted average price of oil after hedging, partially offset by a 25 Mbbbl increase in crude oil production in the West Coast region. Other revenue decreased \$2.6 million due primarily to the impact of mark-to-market adjustments related to ineffectiveness on oil hedge contracts recorded in the prior year. In addition, gas processing plant revenue decreased \$0.9 million.

Refer to further discussion of derivative financial instruments in the “Market Risk Sensitive Instruments” section that follows. Refer to the tables above for production and price information.

Earnings

2020 Compared with 2019

The Exploration and Production segment's loss for 2020 was \$326.9 million, compared with earnings of \$111.8 million for 2019, a decrease of \$438.7 million. The decrease in earnings was primarily attributable to impairments of oil and gas properties (\$326.3 million) and the establishment of a deferred tax valuation allowance in March 2020 (\$60.5 million).

Additionally, earnings decreased due to lower natural gas prices after hedging (\$66.6 million), lower crude oil prices after hedging (\$8.7 million), higher depletion expense (\$13.7 million), higher production and transportation expenses (\$13.5 million), higher other operating expenses (\$0.7 million), the impact of mark-to-market adjustments related to hedging ineffectiveness recorded in the prior year (\$1.7 million), higher interest expense (\$2.6 million), a higher effective tax rate (\$0.7 million) and the impact of a remeasurement of the segment's accumulated deferred income taxes in the prior year that did not recur in fiscal 2020 (\$1.0 million). The increase in depletion expense was primarily due to the increase in production, partially offset by a decrease in the depletion rate as a result of the Appalachian acquisition coupled with ceiling test impairments. The increase in production and transportation expenses was primarily due to increased gathering and transportation costs in the Appalachian region offset by lower steam fuel costs in the West Coast region. The increase in other operating expenses was largely due to an increase in accretion costs associated with asset retirement obligations. The increase in interest expense was primarily due to interest on additional intercompany long-term borrowings associated with the Company's June 2020 unsecured debt issuance coupled with higher short-term borrowings.

The factors discussed above, which decreased earnings during 2020 compared to 2019, were partially offset by higher natural gas production (\$56.9 million), higher crude oil production (\$1.2 million) and lower other taxes (\$1.6 million). The decrease in other taxes primarily reflects an adjustment to Pennsylvania impact fees in fiscal 2019 that did not recur in fiscal 2020.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30	
	2020	2019
	(Thousands)	
Firm Transportation	\$ 228,457	\$ 207,935
Interruptible Transportation	934	1,249
	<u>229,391</u>	<u>209,184</u>
Firm Storage Service	79,031	75,481
Interruptible Storage Service	42	3
	<u>79,073</u>	<u>75,484</u>
Other	1,140	3,615
	<u>\$ 309,604</u>	<u>\$ 288,283</u>

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30	
	2020	2019
Firm Transportation	752,773	718,294
Interruptible Transportation	2,859	2,163
	<u>755,632</u>	<u>720,457</u>

2020 Compared with 2019

Operating revenues for the Pipeline and Storage segment increased \$21.3 million in 2020 as compared with 2019. The increase in operating revenues was primarily due to an increase in transportation revenues of \$20.2 million and an increase in storage revenue of \$3.6 million slightly offset by a decrease in other revenues of \$2.5 million. The increase in transportation and storage revenues was primarily due to an increase in Supply Corporation's transportation and storage rates effective February 1, 2020 related to the rate case settlement. The settlement was approved by the FERC on June 1, 2020. Transportation revenues also increased due to the Empire North project going into service during the fourth quarter of 2020 combined with an increase in Empire's transportation rates effective January 1, 2019 in accordance with Empire's rate case settlement, which was approved by the FERC on May 3, 2019, and an increase in demand charges for transportation service from Supply Corporation's Line N to Monaca Project, which was placed in service in November 2019. These increases were partially offset by a decrease in transportation revenues attributable to an Empire system transportation contract termination in December 2018. The increase in storage revenues, due to the increase in Supply Corporation's rates from the rate case settlement, was partially offset by a decrease in storage revenues from a decline in demand charges from Supply Corporation's storage service as a result of the termination of a temporary contract and higher discounts on storage service. The decrease in other revenues was primarily due to proceeds received by Supply Corporation in the first quarter of fiscal 2019 related to a contract termination as a result of a shipper's bankruptcy that did not recur during fiscal 2020.

Transportation volume increased by 35.2 Bcf in 2020 as compared with 2019. The increase in transportation volume primarily reflected an increase in capacity utilization by certain contract shippers and incremental transportation volume from the Empire North project going into service, partially offset by a decrease in volume from warmer weather. 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.

Earnings

2020 Compared with 2019

The Pipeline and Storage segment's earnings in 2020 were \$78.9 million, an increase of \$4.9 million when compared with earnings of \$74.0 million in 2019. The increase in earnings was primarily due to the impact of higher operating revenues of \$16.8 million, as discussed above, combined with a decrease in operating expenses (\$5.7 million). The decrease in operating expenses was primarily due to lower compressor and facility maintenance costs, lower pipeline integrity costs and a decrease in personnel and compensation costs. These earnings increases were partially offset by an increase in depreciation expense (\$7.1 million), higher income tax expense (\$3.2 million), an increase in property taxes (\$1.8 million), higher interest expense (\$2.8 million), and a decrease in other income (\$3.3 million). The increase in depreciation expense was primarily due to an increase in Supply Corporation's depreciation rates associated with its rate case settlement. Income tax expense was higher due to permanent differences related to stock compensation activity. The increase in property taxes was due to the scheduled phase-out of tax incentives in certain jurisdictions along the Empire system, as well as higher town, county and school taxes due to an increase in assessed values from new projects placed in service. The increase in interest expense was primarily due to interest on additional intercompany long-term borrowings associated with the Company's June 2020 unsecured debt issuance. The decrease in other income was primarily due to higher non-service pension and post-retirement benefit costs in fiscal 2020 compared to non-service pension and post-retirement income in fiscal 2019, partially offset by an increase in allowance for funds used during construction (equity component) mainly related to the construction of the Empire North Project.

GATHERING

Revenues

Gathering Operating Revenues

	Year Ended September 30	
	2020	2019
	(Thousands)	
Gathering	\$ 142,893	\$ 127,064
Processing and Other Revenues	—	11
	<u>\$ 142,893</u>	<u>\$ 127,075</u>

Gathering Volume — (MMcf)

	Year Ended September 30	
	2020	2019
Gathered Volume	<u>264,305</u>	<u>234,760</u>

2020 Compared with 2019

Operating revenues for the Gathering segment increased \$15.8 million in 2020 as compared with 2019, which was driven primarily by a 29.5 Bcf increase in gathered volume. Midstream Company experienced a 13.2 Bcf increase in gathered volume at its Clermont gathering system, a 9.4 Bcf increase in gathered volume at its Trout Run gathering system, and an 8.7 Bcf increase in gathered volume at its Covington gathering system. The increase in gathered volume for the Covington gathering system is due to the acquisition of midstream gathering assets from Shell on July 31, 2020. The acquisition from Shell is discussed below under Capital Resources and Liquidity. These increases were partially offset by a 1.8 Bcf decrease in gathered volume at the Wellsboro gathering system. The 29.5 Bcf net increase in gathered volume can be attributed to the increase in Seneca's Marcellus and Utica gas production.

Earnings

2020 Compared with 2019

The Gathering segment's earnings in 2020 were \$68.6 million, an increase of \$10.2 million when compared with earnings of \$58.4 million in 2019. The increase in earnings was primarily attributable to higher gathering revenues (\$12.5 million) driven by the increase in gathered volume (discussed above) and lower income tax expense (\$1.0 million). Additionally, the Gathering segment's earnings were positively impacted (\$3.8 million) as a result of the Gathering segment's initial recognition of an income tax benefit in March 2020 that was recorded 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. Taxable income generated in the Gathering segment is used to offset taxable losses in the Exploration and Production segment, which provided the opportunity to reduce the valuation allowance recorded in the Exploration and Production segment. These earnings increases were partially offset by higher operating expenses (\$3.4 million), higher depreciation expense (\$1.9 million), higher interest expense (\$1.2 million) and the impact of a nonrecurring income tax benefit recorded in the prior year to adjust the remeasurement of deferred income taxes resulting from the 2017 Tax Reform Act (\$0.5 million). The increase in operating expenses was largely due to major overhaul maintenance of compressor units at Covington and Trout Run gathering system compressor stations during fiscal 2020 and higher lease compression expense related to the operation of the midstream gathering assets acquired from Shell. This acquisition also contributed to higher depreciation expense at the Covington gathering system due to higher plant balances. The Trout Run, Clermont and Wellsboro gathering systems also contributed to the increase in depreciation expense due to higher plant balances. The increase in interest expense is primarily driven by additional long-term borrowings from the Company's long-term debt issuance in June 2020.

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30	
	2020	2019
	(Thousands)	
Retail Revenues:		
Residential	\$ 478,503	\$ 536,854
Commercial	61,643	72,657
Industrial	3,305	4,814
	543,451	614,325
Transportation	114,128	121,747
Other	(5,281)	(8,630)
	<u>\$ 652,298</u>	<u>\$ 727,442</u>

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30	
	2020	2019
Retail Sales:		
Residential	60,977	63,828
Commercial	8,798	9,489
Industrial	537	702
	70,312	74,019
Transportation	68,272	76,028
	<u>138,584</u>	<u>150,047</u>

Degree Days

Year Ended September 30		Percent (Warmer) Colder Than			
		Normal	Actual	Normal(1)	Prior Year(1)
2020	Buffalo, NY	6,653	6,103	(8.3)%	(8.9)%
	Erie, PA	6,181	5,449	(11.8)%	(7.8)%
2019	Buffalo, NY	6,617	6,699	1.2 %	4.8 %
	Erie, PA	6,147	5,911	(3.8)%	(1.1)%

(1) Percents compare actual degree days to normal degree days and actual degree days to actual prior year degree days.

2020 Compared with 2019

Operating revenues for the Utility segment decreased \$75.1 million in 2020 compared with 2019. The decrease largely resulted from a \$70.9 million decrease in retail gas sales revenues and a \$7.6 million decrease in transportation revenue. The decrease in retail gas sales revenues was largely a result of a decrease in the cost of gas sold (per Mcf) coupled with lower throughput due to warmer weather. The decline in transportation revenues was primarily due to a 7.8 Bcf decrease in transportation throughput due to warmer weather and the migration of residential transportation customers previously served by marketers to retail service provided by the Utility segment. These decreases were partially offset by a \$3.3 million increase in other revenues. The increase in other revenues was largely due to a smaller estimated refund provision in the Pennsylvania

jurisdiction recorded during fiscal 2020 for the current income tax benefits resulting from the 2017 Tax Reform Act (\$1.9 million), along with the impact of other regulatory revenue adjustments, including a lower earnings sharing accrual recorded in fiscal 2020 in the segment's New York service territory.

Purchased Gas

The cost of purchased gas is the Company's single largest operating expense. Annual variations in purchased gas costs are attributed directly to changes in gas sales volume, the price of gas purchased and the operation of purchased gas adjustment clauses. Distribution Corporation recorded \$263.1 million and \$342.8 million of Purchased Gas expense during 2020 and 2019, respectively. Under its purchased gas adjustment clauses in New York and Pennsylvania, Distribution Corporation is not allowed to profit from fluctuations in gas costs. Purchased Gas expense recorded on the consolidated income statement matches the revenues collected from customers, a component of Operating Revenues on the consolidated income statement. Under mechanisms approved by the NYPSC in New York and the PaPUC in Pennsylvania, any difference between actual purchased gas costs and what has been collected from the customer is deferred on the consolidated balance sheet as either an asset, Unrecovered Purchased Gas Costs, or a liability, Amounts Payable to Customers. These deferrals are subsequently collected from the customer or passed back to the customer, subject to review by the NYPSC and the PaPUC. Absent disallowance of full recovery of Distribution Corporation's purchased gas costs, such costs do not impact the profitability of the Company. Purchased gas costs impact cash flow from operations due to the timing of recovery of such costs versus the actual purchased gas costs incurred during a particular period. Distribution Corporation's purchased gas adjustment clauses seek to mitigate this impact by adjusting revenues on either a quarterly or monthly basis.

Distribution Corporation contracts for firm long-term transportation and storage capacity with rights-of-first-refusal from nine upstream pipeline companies including Supply Corporation for transportation and storage and Empire for transportation. Distribution Corporation contracts for firm gas supplies on term and spot bases with various producers, marketers and one local distribution company to meet its gas purchase requirements. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Earnings

2020 Compared with 2019

The Utility segment's earnings in 2020 were \$57.4 million, a decrease of \$3.5 million when compared with earnings of \$60.9 million in 2019. The decrease in earnings was largely attributable to higher operating expenses (\$8.5 million), which were largely a result of higher personnel costs and an increase to the allowance for bad debt expense, the impacts of lower usage and weather on customer margins (\$1.1 million) and higher depreciation expense (\$1.1 million). The increase to the allowance for bad debt expense is related to the COVID-19 pandemic as the Company recorded incremental expense due to the potential for future customer non-payment given the current economic environment. The increase in depreciation expense is a reflection of an increase in property, plant and equipment balances year over year. These decreases were slightly offset by the positive earnings impact related to the system modernization tracker (\$3.1 million), regulatory true-up adjustments (\$2.8 million), including a lower earnings sharing accrual, a favorable impact associated with higher other income and lower other deductions (\$0.5 million), largely due to higher interest income on regulatory deferrals and lower non-service pension costs, and lower interest expense (\$0.7 million). The decrease in interest expense reflects lower short-term borrowings, lower interest costs on long-term borrowings and lower interest costs on customer deposits.

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 2020, the WNC increased earnings by approximately \$3.5 million, as the weather was warmer than normal. In 2019, the WNC decreased earnings by approximately \$1.0 million, as the weather was colder than normal.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of NFR, the operations of Seneca's Northeast Division and corporate operations. NFR marketed natural gas to industrial, wholesale, commercial, public authority and residential customers primarily in western and central New York and northwestern Pennsylvania. NFR completed the sale of its commercial and industrial contracts and certain other assets on August 1, 2020 and is winding down its operations. Seneca's Northeast Division markets timber from its New York and Pennsylvania land holdings.

Earnings

2020 Compared with 2019

All Other and Corporate operations recorded a loss of \$1.7 million in 2020, which was \$0.9 million higher than the loss of \$0.8 million in 2019. The decrease in earnings was primarily attributable to the impact of the prior year remeasurement of deferred income taxes under the 2017 Tax Reform Act that lowered income tax expense for fiscal 2019 (\$3.5 million), coupled with higher interest expense (\$2.6 million), largely due to short-term borrowings from the Company's committed credit facility and uncommitted lines of credit during the current year, and higher income tax expense (\$1.3 million). The increase in income tax expense can be attributed to the impact of less favorable consolidated tax sharing provisions in fiscal 2020, higher state taxes and a lower tax benefit due to differences in book and tax treatment of stock compensation. The earnings impact of these items was partially offset by unrealized gains on investments in equity securities recorded during fiscal 2020 compared to unrealized losses during fiscal 2019 (\$2.9 million), the impact of higher energy marketing margins (\$3.0 million) and lower operating expenses (\$0.4 million).

INTEREST CHARGES

Although most of the variances in Interest Charges are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis (amounts below are pre-tax amounts):

Interest on long-term debt increased \$8.4 million in 2020 as compared to 2019. This increase was due in large part to the issuance of \$500 million of 5.50% notes in June 2020.

Other interest expense increased \$1.9 million in 2020 as compared to 2019. The increase was primarily due to higher average short-term debt balances in 2020 compared to 2019.

CAPITAL RESOURCES AND LIQUIDITY

The primary sources and uses of cash during the last two years are summarized in the following condensed statement of cash flows:

	Year Ended September 30	
	2020	2019
	(Millions)	
Provided by Operating Activities	\$ 740.8	\$ 694.5
Capital Expenditures	(716.2)	(788.9)
Acquisition of Upstream Assets and Midstream Gathering Assets	(506.3)	—
Other Investing Activities	(1.1)	(10.3)
Change in Notes Payable to Banks and Commercial Paper	(25.2)	55.2
Net Proceeds from Issuance of Long-Term Debt	493.0	—
Net Proceeds from Issuance (Repurchase) of Common Stock	161.6	(8.9)
Dividends Paid on Common Stock	(153.3)	(147.4)
Net Decrease in Cash, Cash Equivalents, and Restricted Cash	<u>\$ (6.7)</u>	<u>\$ (205.8)</u>

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items

include depreciation, depletion and amortization, impairment of oil and gas producing properties, deferred income taxes and stock-based compensation.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from year to year 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.

Cash provided by operating activities in the Exploration and Production segment may vary from year to year 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 \$740.8 million in 2020, an increase of \$46.3 million compared with the \$694.5 million provided by operating activities in 2019. The increase in cash provided by operating activities primarily reflects higher cash provided by operating activities in the Exploration and Production segment and the Pipeline and Storage segment. The increase in the Exploration and Production segment was primarily due to the impact of the 2017 Tax Reform Act that repealed the corporate alternative minimum tax and provided that the Company's existing AMT credit carryovers were refundable, if not utilized to reduce tax. Installments of AMT credit refunds were received in January 2020 and June 2020. The AMT credit refund received in June 2020 was an accelerated recovery provided by the federal government under the CARES Act. The receipt of the AMT credit refunds more than offset lower cash receipts from natural gas and oil production. 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 Supply Corporation's Line N to Monaca Project that went in service in November 2019.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets, including non-cash capital expenditures, totaled \$1.2 billion and \$781.2 million in 2020 and 2019, respectively. The table below presents these expenditures:

	Year Ended September 30	
	2020	2019
	(Millions)	
Exploration and Production:		
Capital Expenditures(1)	\$ 670.4 (3)	\$ 491.9 (4)
Pipeline and Storage:		
Capital Expenditures	\$ 166.7 (3)	143.0 (4)
Gathering:		
Capital Expenditures(2)	\$ 297.8 (3)	49.7 (4)
Utility:		
Capital Expenditures	\$ 94.3 (3)	95.8 (4)
All Other and Corporate:		
Capital Expenditures	\$ 0.5	0.8
Eliminations	\$ (1.1)	—
Total Expenditures	<u>\$1,228.6</u>	<u>\$ 781.2</u>

- (1) 2020 includes \$282.8 million related to the acquisition of upstream assets acquired from Shell, of which \$281.7 million is included in Property, Plant and Equipment and \$1.1 million is included in Materials, Supplies and Emission Allowances. The acquisition cost is reported as a component of Acquisition of Upstream Assets and Midstream Gathering Assets on the Consolidated Statement of Cash Flows.

- (2) 2020 includes \$223.5 million related to the acquisition of midstream gathering assets acquired from Shell, of which \$223.4 million is included in Property, Plant and Equipment and \$0.1 million is included in Materials, Supplies and Emission Allowances. The acquisition cost is reported as a component of Acquisition of Upstream Assets and Midstream Gathering Assets on the Consolidated Statement of Cash Flows.
- (3) 2020 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include \$45.8 million, \$17.3 million, \$13.5 million and \$10.7 million, respectively, of non-cash capital expenditures.
- (4) 2019 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include \$38.0 million, \$23.8 million, \$6.6 million and \$12.7 million, respectively, of non-cash capital expenditures.

Exploration and Production

In 2020, the majority of the Exploration and Production segment capital expenditures were well drilling and completion expenditures, and also included \$282.8 million of expenditures related to the acquisition of upstream assets acquired from Shell on July 31, 2020. The acquisition includes over 400,000 net acres in Appalachia, with approximately 200,000 net acres in Tioga County. The proved developed and undeveloped natural gas reserves associated with this acquisition amounted to 684,141 MMcf. Capital expenditures were approximately \$639.7 million for the Appalachian region (including \$412.0 million in the Marcellus Shale area and \$204.6 million in the Utica Shale area) and \$30.7 million for the West Coast region. These amounts included approximately \$219.9 million spent to develop proved undeveloped reserves.

In 2019, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately \$460.5 million for the Appalachian region (including \$201.0 million in the Marcellus Shale area and \$243.4 million in the Utica Shale area) and \$31.4 million for the West Coast region. These amounts included approximately \$246.0 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The majority of the Pipeline and Storage segment's capital expenditures for 2020 were related to additions, improvements and replacements to this segment's transmission and gas storage systems. In addition, the Pipeline and Storage segment capital expenditures for 2020 included expenditures related to the Empire North Project (\$68.9 million), Supply Corporation's Line N to Monaca Project (\$4.1 million) and Supply Corporation's FM100 Project (\$3.7 million).

The majority of the Pipeline and Storage segment's capital expenditures for 2019 were related to additions, improvements and replacements to this segment's transmission and gas storage systems. In addition, the Pipeline and Storage segment capital expenditures for 2019 included expenditures related to the Empire North Project (\$26.2 million) and Supply Corporation's Line N to Monaca Project (\$16.6 million).

Gathering

The majority of the Gathering segment's capital expenditures for 2020 were for the acquisition of midstream gathering assets from Shell in the amount of \$223.5 million. These gathering assets, including approximately 238 miles of gathering pipeline, support the upstream assets in Tioga County that the Exploration and Production segment acquired from Shell, as discussed above, and are interconnected with various interstate pipelines, including the Company's Empire pipeline systems. In addition, the Gathering segment's capital expenditures included expenditures related to the continued expansion of Midstream Company's Trout Run, Clermont, and Wellsboro gathering systems, as discussed below. Midstream Company spent \$36.5 million, \$19.7 million and \$17.3 million, respectively, in 2020 on the development of the Trout Run, Clermont and Wellsboro gathering systems. These expenditures were largely attributable to the continued development of centralized station facilities, including increased compression horsepower at the Trout Run and Wellsboro gathering systems and additional dehydration on the Clermont gathering system. The Trout Run expenditures also included costs to construct new pipeline and station facilities to bring a third party producer online.

The majority of the Gathering segment's capital expenditures for 2019 were for the continued expansion of Midstream Company's Trout Run gathering system, Midstream Company's Clermont gathering system and Midstream Company's Wellsboro gathering system. Midstream Company spent \$26.6 million, \$9.2 million and \$11.5 million, respectively, in 2019 on the development of the Trout Run, Clermont and Wellsboro gathering systems. These expenditures were largely attributable to the continued development of centralized station facilities, including increased compression horsepower at the Trout Run and Clermont gathering systems and a new natural gas dehydration plant at the Wellsboro gathering system.

Utility

The majority of the Utility segment's capital expenditures for 2020 and 2019 were made for main and service line improvements and replacements, as well as main extensions.

Estimated Capital Expenditures

The Company's estimated capital expenditures for the next three years are:

	Year Ended September 30		
	2021	2022	2023
	(Millions)		
Exploration and Production(1)	\$ 370	\$ 425	\$ 350
Pipeline and Storage	275	125	75
Gathering	35	50	75
Utility	95	100	100
All Other	—	—	—
	<u>\$ 775</u>	<u>\$ 700</u>	<u>\$ 600</u>

- (1) Includes estimated expenditures for the years ended September 30, 2021, 2022 and 2023 of approximately \$134 million, \$113 million and \$27 million, respectively, to develop proved undeveloped reserves. The Company is committed to developing its proved undeveloped reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting.

Exploration and Production

Estimated capital expenditures in 2021 for the Exploration and Production segment include approximately \$360 million for the Appalachian region and \$10 million for the West Coast region.

Estimated capital expenditures in 2022 for the Exploration and Production segment include approximately \$405 million for the Appalachian region and \$20 million for the West Coast region.

Estimated capital expenditures in 2023 for the Exploration and Production segment include approximately \$330 million for the Appalachian region and \$20 million for the West Coast region.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2021 through 2023 are expected to include: construction of new pipeline and compressor stations to support expansion projects, the replacement of transmission and storage lines, the reconditioning of storage wells and improvements of compressor stations. Expansion projects where the Company has begun to make significant investments of preliminary survey and investigation costs and/or where shipper agreements have been executed are described below.

In light of the continuing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus and Utica Shale producing areas — Supply Corporation and Empire have completed and continue to pursue several expansion projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines and to on-system markets, and markets beyond the Supply Corporation and Empire pipeline systems. Preliminary survey and investigation costs for expansion, routine replacement or modernization projects are initially recorded as Deferred Charges on the Consolidated Balance Sheet. Management may reserve for preliminary survey and investigation costs associated with large projects by reducing the Deferred Charges balance and increasing Operation and Maintenance Expense on the

Consolidated Statement of Income. If it is determined that it is highly probable that a project for which a reserve has been established will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. The amounts remain in Deferred Charges until such time as capital expenditures for the project have been incurred and activities that are necessary to get the construction project ready for its intended use are in progress. At that point, the balance is transferred from Deferred Charges to Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet.

Supply Corporation completed a project to provide incremental natural gas transportation services from Line N to the ethane cracker facility being constructed by Shell Chemical Appalachia, LLC in Potter Township, Pennsylvania ("Line N to Monaca Project"), with transportation service beginning on November 1, 2019. This project involved construction of a 4.5 mile pipeline extension from Line N to the facility and has resulted in Supply Corporation securing incremental firm transportation capacity commitments totaling 133,000 Dth per day on Line N and on the pipeline extension to the facility. Supply Corporation was authorized to pursue the project by FERC under its blanket certificate as of May 30, 2018. As of September 30, 2020, approximately \$22.9 million has been spent on the Line N to Monaca Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2020.

Empire concluded an Open Season on November 18, 2015, and designed a project to allow 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 TGP 200 Line ("Empire North Project"). This project is fully subscribed under long term agreements and received the FERC Section 7(c) certificate on March 7, 2019. On July 11, 2020, Empire placed the Jackson Compressor Station in service to begin partial, interim service. The remaining Empire North facilities were placed in service on September 15, 2020. The estimated capital cost of the project is approximately \$129 million. As of September 30, 2020, approximately \$114.2 million has been spent on the Empire North Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2020. The remaining expenditures expected to be spent are included in Pipeline and Storage estimated capital expenditures in the table above.

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 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. The FM100 Project has a target in-service date in late calendar 2021 and a preliminary cost estimate of approximately \$280 million. As of September 30, 2020, approximately \$14.5 million has been spent on the FM100 Project, including \$10.6 million spent to study the project that is included in Deferred Charges on the Consolidated Balance Sheet. The remaining \$3.9 million spent on the project has been capitalized as Construction Work in Progress. The remaining expenditures expected to be spent on the project are included in Pipeline and Storage estimated capital expenditures in the table above.

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 have been appealed and are pending in a separate action before the Second Circuit Court of Appeals. 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 actions. As of September 30, 2020, approximately \$58.7 million has been spent on the Northern Access project, including \$24.0 million that has been spent to study the project, for which no reserve has been established. The remaining \$34.7 million spent on the project has been capitalized as Construction Work in Progress. Because it is difficult to predict the timing of the resolution of the litigation process, no estimated capital expenditures for the Northern Access Project are included in the table above.

Gathering

The majority of the Gathering segment capital expenditures in 2021 through 2023, included in the table above, are expected to be for construction and expansion of gathering systems, as discussed below.

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. Estimated capital expenditures in 2021 through 2023 include anticipated expenditures in the range of \$100 million to \$130 million for the continued expansion of the Clermont gathering system.

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. Estimated capital expenditures in 2021 through 2023 include anticipated expenditures in the range of \$10 million to \$20 million for the continued expansion of the Trout Run gathering system.

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. Estimated capital expenditures in 2021 through 2023 include anticipated expenditures in the range of \$5 million to \$15 million for the continued expansion of the Wellsboro gathering system.

NFG Midstream Covington, LLC, a wholly-owned subsidiary of Midstream Company, operates its Covington gathering system as well as the Tioga gathering system acquired from Shell on July 31, 2020, both in Tioga County, Pennsylvania. The current Covington gathering system consists of two compressor stations and backbone and in-field gathering pipelines. The Tioga gathering system consists of 13 compressor stations and backbone and in-field gathering pipelines. Estimated capital expenditures in 2021 through 2023 include anticipated expenditures in the range of \$20 million to \$35 million for continued expansion of the Tioga gathering system.

Utility

Capital expenditures for the Utility segment in 2021 through 2023 are expected to be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment.

Project Funding

Over the past two years, the Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment and Utility segment capital expenditures, with cash from operations and short-term debt. The Company also issued long-term debt and common stock in June 2020, as discussed below. Going forward, the Company expects to use proceeds from the sale of Timber properties, discussed above, as well as cash from operations and short-term borrowings to finance these 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 prices combined with production from existing wells. As disclosed above, the Company is precluded from issuing new long-term debt beginning in January 2021 as a means of financing these projects. The Company expects this restriction to extend for several quarters in fiscal 2021.

The Company continuously evaluates capital expenditures and potential investments in corporations, partnerships, and other business entities. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, natural gas storage facilities, 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 conditions.

FINANCING CASH FLOW

Consolidated short-term debt decreased \$25.2 million when comparing the balance sheet at September 30, 2020 to the balance sheet at September 30, 2019. The maximum amount of short-term debt outstanding during the year ended September 30, 2020 was \$250.0 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. Given the effects on credit markets of the COVID-19 pandemic, access to commercial paper markets became challenging and more expensive beginning in March 2020. As a result, the Company elected to draw on its Credit Agreement (as defined below) and its uncommitted lines of credit as alternative sources of short-term capital and liquidity. The balances drawn under the Credit Agreement remained until June 8, 2020, at which time the Company repaid the full \$200.0 million outstanding with the proceeds from the Company's common stock and long-term debt issuances discussed below. During the quarter ended September 30, 2020, the Company returned to the commercial paper markets, and utilized that market, in conjunction with borrowings under its Credit Agreement, to meet its short-term borrowing needs. At September 30, 2020, the Company had outstanding short-term notes payable to banks of \$15.0 million, all of which was issued under the Credit Agreement. The Company had outstanding commercial paper of \$15.0 million at September 30, 2020.

On October 25, 2018, the Company entered into a Fourth Amended and Restated Credit Agreement ("Credit Agreement") with a syndicate of 12 banks. This Credit Agreement provides a \$750.0 million multi-year unsecured committed revolving credit facility through October 25, 2023. On May 4, 2020, the Company entered into a 364-Day Credit Agreement with a syndicate of 10 banks, all of which are also lenders under the Credit Agreement. The 364-Day Credit Agreement provides an additional \$200.0 million unsecured committed revolving credit facility. 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 Company's 364-Day Credit Agreement. Since July 1, 2018, the Company recorded after-tax ceiling test impairments totaling \$326.3 million. As a result, at September 30, 2020, \$163.1 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 .55. The constraints specified in both the Credit Agreement and 364-Day Credit Agreement would have permitted an additional \$1.30 billion in short-term and/or long-term debt to be outstanding at September 30, 2020 (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

On March 27, 2020, the Company was downgraded by S&P to a rating of BBB- with a negative outlook. S&P subsequently improved the Company's outlook to stable during the quarter ended June 30, 2020. Combined with current ratings from other credit rating agencies, the downgrade increased the Company's short-term borrowing costs under its Credit Agreement. A further 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 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 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 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 at September 30, 2020 and September 30, 2019 had a maturity date within the next twelve months.

The Company's embedded cost of long-term debt was 4.85% and 4.69% at September 30, 2020 and September 30, 2019, respectively. Refer to "Interest Rate Risk" in this Item for a more detailed breakdown of the Company's embedded cost of long-term debt.

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.

The Company's present liquidity position is believed to be adequate to satisfy known demands. Under the Company's existing indenture covenants at September 30, 2020, the Company is precluded from issuing incremental long-term unsecured indebtedness beginning in January 2021 as a result of impairments of its oil and gas properties recognized during the year ended September 30, 2020, as discussed above. The Company expects this restriction to extend for several quarters in fiscal 2021. Depending on the magnitude of any future impairments, it is possible that the Company's indenture covenants could restrict the Company's ability to issue additional long-term unsecured indebtedness beyond that period. The covenants would not preclude the Company from issuing long-term debt to replace maturing long-term debt, including the Company's 4.90% notes, in the principal amount of \$500 million, maturing in December 2021. 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 September 30, 2020) 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.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2020, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						Total
	2021	2022	2023	2024	2025	Thereafter	
	(Millions)						
Long-Term Debt, including interest expense(1)	\$ 127.6	\$ 607.2	\$ 639.3	\$ 80.7	\$ 574.6	\$ 1,172.9	\$ 3,202.3
Operating Lease Obligations	\$ 5.0	\$ 3.1	\$ 2.5	\$ 2.2	\$ 2.1	\$ 7.6	\$ 22.5
Purchase Obligations:							
Utility Gas Purchase Contracts(2)	\$ 136.1	\$ —	\$ —	\$ —	\$ —	\$ —	\$ 136.1
Transportation and Storage Contracts(3)	\$ 45.8	\$ 111.3	\$ 120.9	\$ 129.3	\$ 146.3	\$ 1,128.2	\$ 1,681.8
Exploration and Production Activities(4)	\$ 109.3	\$ 15.2	\$ 0.7	\$ —	\$ —	\$ —	\$ 125.2
Pipeline, Compressor and Gathering Projects	\$ 98.3	\$ 6.4	\$ 3.4	\$ 3.3	\$ 3.3	\$ 10.3	\$ 125.0
Other	\$ 18.5	\$ 10.2	\$ 8.6	\$ 6.9	\$ 6.6	\$ 26.1	\$ 76.9

(1) Refer to Note H — Capitalization and Short-Term Borrowings, as well as the table under Interest Rate Risk in the Market Risk Sensitive Instruments section below, for the amounts excluding interest expense.

(2) Gas prices are variable based on the NYMEX prices adjusted for basis.

(3) Includes commitments for firm transportation and storage services under existing contracts executed by the Utility segment and commitments for firm transportation services under existing contracts and

precedent agreements executed by the Exploration and Production segment with various third party pipelines.

- (4) Includes hydraulic fracturing and other completion services, well tending services, well workover activities, tubing and casing, production equipment, contracts for drilling rig services and steam fuel purchases.

The Company has other long-term obligations recorded on its Consolidated Balance Sheets that are not reflected in the table above. Such long-term obligations include pension and other post-retirement liabilities, asset retirement obligations, deferred income tax liabilities, various regulatory liabilities, derivative financial instrument liabilities and other deferred credits (the majority of which consist of liabilities for non-qualified benefit plans, deferred compensation liabilities, environmental liabilities and workers compensation liabilities).

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the Consolidated Balance Sheets in accordance with the authoritative guidance (see Item 7, MD&A under the heading “Critical Accounting Estimates - Accounting for Derivative Financial Instruments”); and (ii) other obligations which are reflected on the Consolidated Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note L — Commitments and Contingencies, 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.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan). The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it will continue making contributions to the Retirement Plan. During 2020, the Company contributed \$24.6 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2021 will be in the range of \$15.0 million to \$25.0 million. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments or through cash on hand, cash from operations or short-term borrowings.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The Company has established VEBA trusts and 401(h) accounts for its other post-retirement benefits. The Company has been making contributions to its VEBA trusts and/or 401(h) accounts over the last several years and anticipates that it will continue making contributions to the VEBA trusts and/or 401(h) accounts. During 2020, the Company contributed \$2.8 million to its VEBA trusts. In addition, the Company made direct payments of \$0.3 million to retirees not covered by the VEBA trusts and 401(h) accounts during 2020. The Company anticipates that the annual contribution to its VEBA trusts in 2021 will be in the range of \$2.5 million to \$3.0 million. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company uses various derivative financial instruments (derivatives), including price swap agreements and no cost collars, as part of the Company’s overall energy commodity price risk management strategy in its Exploration and Production segment. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more

stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from, or pay to, the respective counterparties at September 30, 2020 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial instruments.

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

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

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

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2020, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company's (assuming the derivative is in a loss position) credit default swaps rates.

The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2020. At September 30, 2020, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2024.

Natural Gas Price Swap Agreements

	Expected Maturity Dates				
	2021	2022	2023	2024	Total
Notional Quantities (Equivalent Bcf)	145.0	93.6	19.7	1.1	259.4
Weighted Average Fixed Rate (per Mcf)	\$ 2.72	\$ 2.68	\$ 2.58	\$ 2.53	\$ 2.69
Weighted Average Variable Rate (per Mcf)	\$ 2.96	\$ 2.80	\$ 2.57	\$ 2.45	\$ 2.87

At September 30, 2020, the Company would have paid its respective counterparties an aggregate of approximately \$45.7 million to terminate the natural gas price swap agreements outstanding at that date.

At September 30, 2019, the Company had natural gas price swap agreements covering 99.1 Bcf at a weighted average fixed rate of \$2.86 per Mcf.

Crude Oil Price Swap Agreements

	Expected Maturity Dates		
	2021	2022	Total
Notional Quantities (Equivalent Bbls)	1,092,000	456,000	1,548,000
Weighted Average Fixed Rate (per Bbl)	\$ 58.24	\$ 56.97	\$ 57.87
Weighted Average Variable Rate (per Bbl)	\$ 43.87	\$ 45.59	\$ 44.37

At September 30, 2020, the Company would have received from its respective counterparties an aggregate of approximately \$20.9 million to terminate the crude oil price swap agreements outstanding at that date.

At September 30, 2019, the Company had crude oil price swap agreements covering 2,772,000 Bbls at a weighted average fixed rate of \$60.93 per Bbl.

No Cost Collars

The following table discloses the notional quantities, the weighted average ceiling price and the weighted average floor price for the no cost collars used by the Company to manage natural gas price risk. The no cost collars provide for the Company to receive monthly payments from (or make payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). At September 30, 2020, the Company had not entered into any natural gas no cost collars extending beyond 2022.

	Expected Maturity Dates		
	2021	2022	Total
Natural Gas			
Notional Quantities (Equivalent Bcf)	25.0	2.3	27.3
Weighted Average Ceiling Price (per Mcf)	\$ 2.87	\$ 2.87	\$ 2.87
Weighted Average Floor Price (per Mcf)	\$ 2.35	\$ 2.35	\$ 2.35

At September 30, 2020, the Company would have had to pay an aggregate of approximately \$8.2 million to terminate the natural gas no cost collars outstanding at that date.

Foreign Exchange Risk

The Company uses 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. All of these transactions are forecasted.

The following table discloses foreign exchange contract information by expected maturity dates. The Company receives a fixed price in exchange for paying a variable price as noted in the Canadian to U.S. dollar forward exchange rates. Notional amounts (Canadian dollars) are used to calculate the contractual payments to be exchanged under contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2020. At September 30, 2020, the Company had not entered into any foreign currency exchange contracts extending beyond 2030.

	Expected Maturity Dates						Total
	2021	2022	2023	2024	2025	Thereafter	
Notional Quantities (Canadian Dollar in millions)	\$ 17.3	\$ 16.1	\$ 14.7	\$ 12.9	\$ 10.9	\$ 6.1	\$78.0
Weighted Average Fixed Rate (\$Cdn/\$US)	\$ 1.30	\$ 1.29	\$ 1.29	\$ 1.29	\$ 1.28	\$ 1.38	\$1.30
Weighted Average Variable Rate (\$Cdn/\$US)	\$ 1.32	\$ 1.31	\$ 1.31	\$ 1.32	\$ 1.31	\$ 1.37	\$1.32

At September 30, 2020, absent other positions with the same counterparties, the Company would have paid its respective counterparties an aggregate of \$1.7 million to terminate these foreign exchange contracts.

Refer to Item 8 at Note J — Financial Instruments for a discussion of the Company’s exposure to credit risk related to its derivative financial instruments.

Interest Rate Risk

The fair value of long-term fixed rate debt is \$2.8 billion at September 30, 2020. This fair value amount is not intended to reflect principal amounts that the Company will ultimately be required to pay. The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company’s long-term fixed rate debt:

Principal Amounts by Expected Maturity Dates							
	2021	2022	2023	2024	2025	Thereafter	Total
(Dollars in millions)							
Long-Term Fixed Rate Debt . . .	\$ —	\$ 500.0	\$ 549.0	\$ —	\$ 500.0	\$ 1,100.0	\$ 2,649.0
Weighted Average Interest Rate Paid	—	4.9%	4.1%	—	5.4%	4.9%	4.8%

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, 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 new law that prohibits utilities from terminating or disconnecting services to any residential customer for non-payment for the duration of the state disaster emergency. In addition, the law prohibits residential terminations for nonpayment for a period of 180 days running from the end of the state disaster emergency for customers that have experienced a change in financial circumstances due to the COVID-19 state of emergency. Governor Cuomo, through the issuance of executive orders, has extended the declaration of the state disaster emergency through December 3, 2020. The duration of the aforementioned suspension in New York and its related impact on the Company is uncertain. The Company is anticipating that there will be some level of deterioration in the collectability of customer receivable balances depending on the depth and duration of the COVID-19 pandemic. 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).

Pennsylvania Jurisdiction

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

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 expire on March 31, 2021 and calling for comments by February 16, 2021 regarding policies the Commission should adopt after March 31, 2021. The order also appears to expand the aforementioned potential utility regulatory asset to all incremental COVID-19 related expenses incurred above those embedded in rates. The Company continues to monitor this item for potential deferral opportunity.

Pipeline and Storage

Supply Corporation's recent 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 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 no party may make a filing for new rates before March 31, 2021. If no rate case has been filed, 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 8 at Note L — Commitments and Contingencies under the heading "Environmental Matters."

While changes in environmental laws and regulations could have an adverse financial impact on the Company, legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

Environmental Regulation

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 current administration has issued executive orders to review and potentially roll back many of these burdensome regulations, and, in turn, litigation (not involving the Company) has been instituted to challenge the administration's efforts. The Company must continue to comply with all applicable regulations. 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. 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 to 60% of 1990 levels by 2030, and to 15% of 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. These 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. Also, refer to the "Corporate Responsibility" section at the beginning of this Item 7, MD&A.

EFFECTS OF INFLATION

Although the rate of inflation has been relatively low over the past few years, the Company's operations remain sensitive to increases in the rate of inflation because of its capital spending and the regulated nature of a significant portion of its business.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "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. The Company's ability to successfully integrate acquired assets and achieve expected cost synergies;

2. The length and severity of the recent COVID-19 pandemic, including its impacts across our businesses on demand, operations, global supply chains and liquidity;
3. 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;
4. Changes in the price of natural gas or oil;
5. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
6. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;
7. 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;
8. 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;
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. 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;
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.

INDUSTRY AND MARKET DATA DISCLOSURE

The market data and certain other statistical information used throughout this Form 10-K are based on independent industry publications, government publications or other published independent sources. Some data is also based on the Company's good faith estimates. Although the Company believes these third-party sources are reliable and that the information is accurate and complete, it has not independently verified the information.

Item 7A *Quantitative and Qualitative Disclosures About Market Risk*

Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A.

Item 8 *Financial Statements and Supplementary Data*

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All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Supplementary Data

Supplementary data that is included in Note N — Quarterly Financial Data (unaudited) and Note O — Supplementary Information for Oil and Gas Producing Activities (unaudited), appears under this Item, and reference is made thereto.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of National Fuel Gas Company

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes and financial statement schedule, of National Fuel Gas Company and its subsidiaries (the “Company”) as listed in the accompanying index (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of September 30, 2020 based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of September 30, 2020 and 2019 and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2020 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2020, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed 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. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Critical Audit Matters

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that (i) relates to accounts or disclosures that are material to the consolidated financial statements and (ii) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

The Impact of Proved Oil and Gas Reserves on Oil and Gas Properties, Net

As described in Note A to the consolidated financial statements, the Exploration and Production segment includes capitalized costs relating to oil and gas producing activities, net of depreciation, depletion, and amortization (DD&A) of \$1.8 billion as of September 30, 2020, and related DD&A expense of \$166.8 million for the year then ended. The Exploration and Production segment follows the full cost method of accounting. Under this method, all costs associated with property acquisition, exploration and development activities are capitalized and DD&A is computed based on quantities produced in relation to proved reserves using the units of production method. 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. If capitalized costs, net of accumulated DD&A and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. For the year ended September 30, 2020, pre-tax impairment charges of \$449.4 million were recognized. As disclosed by management, in addition to DD&A under the units-of-production method, proved reserves are a major component of the ceiling test. Estimates of the Company's proved oil and gas reserves and the future net cash flows from those reserves were prepared by the Company's petroleum engineers and audited by independent petroleum engineers (together referred to as "management's specialists"). Petroleum engineering involves significant assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Estimates of economically recoverable oil and gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including quantities of oil and gas that are ultimately recovered, the timing of the recovery of oil and gas reserves, the production and operating costs to be incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

The principal considerations for our determination that performing procedures relating to the impact of proved oil and gas reserves on oil and gas properties, net is a critical audit matter are the significant judgment by management, including the use of management's specialists, when developing the estimates of proved oil and

gas reserves, which in turn led to a high degree of auditor judgment, subjectivity and effort in performing procedures and evaluating evidence related to the significant assumption of the quantities of oil and gas that are ultimately recovered.

Addressing the matter involved performing procedures and evaluating audit evidence in connection with forming our overall opinion on the consolidated financial statements. These procedures included testing the effectiveness of controls relating to management's estimates of proved oil and gas reserves that are utilized in the ceiling test and DD&A expense calculations. These procedures also included, among others, evaluating the reasonableness of the significant assumptions used by management related to the quantities of oil and gas that are ultimately recovered. Evaluating the reasonableness of the significant assumptions included evaluating information on additional development activity, production history, if the assumptions used were reasonable considering the past performance of the Company, and whether they were consistent with evidence obtained in other areas of the audit. The work of management's specialists was used in performing the procedures to evaluate the reasonableness of the estimates of proved oil and gas reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood, as well as the methods and assumptions used by the specialists. The procedures performed also included tests of the data used by the specialists and an evaluation of the specialists' findings.

/s/ PRICEWATERHOUSECOOPERS LLP
Buffalo, New York
November 20, 2020

We have served as the Company's auditor since 1941.

NATIONAL FUEL GAS COMPANY
CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS
REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2020	2019	2018
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues:			
Utility and Energy Marketing Revenues	\$ 728,336	\$ 860,985	\$ 812,474
Exploration and Production and Other Revenues	611,885	636,528	569,808
Pipeline and Storage and Gathering Revenues	206,070	195,819	210,386
	<u>1,546,291</u>	<u>1,693,332</u>	<u>1,592,668</u>
Operating Expenses:			
Purchased Gas	233,890	386,265	337,822
Operation and Maintenance:			
Utility and Energy Marketing	181,051	171,472	168,885
Exploration and Production and Other	148,856	147,457	139,546
Pipeline and Storage and Gathering	108,640	111,783	101,338
Property, Franchise and Other Taxes	88,400	88,886	84,393
Depreciation, Depletion and Amortization	306,158	275,660	240,961
Impairment of Oil and Gas Producing Properties	449,438	—	—
	<u>1,516,433</u>	<u>1,181,523</u>	<u>1,072,945</u>
Operating Income	<u>29,858</u>	<u>511,809</u>	<u>519,723</u>
Other Income (Expense):			
Other Income (Deductions)	(17,814)	(15,542)	(21,174)
Interest Expense on Long-Term Debt	(110,012)	(101,614)	(110,946)
Other Interest Expense	(7,065)	(5,142)	(3,576)
Income (Loss) Before Income Taxes	<u>(105,033)</u>	<u>389,511</u>	<u>384,027</u>
Income Tax Expense (Benefit)	18,739	85,221	(7,494)
Net Income (Loss) Available for Common Stock	<u>(123,772)</u>	<u>304,290</u>	<u>391,521</u>
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	1,272,601	1,098,900	851,669
	<u>1,148,829</u>	<u>1,403,190</u>	<u>1,243,190</u>
Dividends on Common Stock	(156,249)	(148,432)	(144,290)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	(950)	—	—
Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities	—	7,437	—
Cumulative Effect of Adoption of Authoritative Guidance for Reclassification of Stranded Tax Effects	—	10,406	—
Balance at End of Year	<u>\$ 991,630</u>	<u>\$ 1,272,601</u>	<u>\$ 1,098,900</u>
Earnings (Loss) Per Common Share:			
Basic:			
Net Income (Loss) Available for Common Stock	<u>\$ (1.41)</u>	<u>\$ 3.53</u>	<u>\$ 4.56</u>
Diluted:			
Net Income (Loss) Available for Common Stock	<u>\$ (1.41)</u>	<u>\$ 3.51</u>	<u>\$ 4.53</u>
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	87,968,895	86,235,550	85,830,597
Used in Diluted Calculation	<u>87,968,895</u>	<u>86,773,259</u>	<u>86,439,698</u>

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2020	2019	2018
	(Thousands of dollars)		
Net Income (Loss) Available for Common Stock	<u>\$ (123,772)</u>	<u>\$ 304,290</u>	<u>\$ 391,521</u>
Other Comprehensive Income (Loss), Before Tax:			
Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(19,214)	(44,089)	6,225
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	15,361	7,332	9,704
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	—	—	132
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	9,862	79,301	(74,103)
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	—	—	(430)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(93,295)	5,464	1,189
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	1,313	—	—
Reclassification Adjustment for the Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities to Earnings Reinvested in the Business	—	(11,738)	—
Other Comprehensive Income (Loss), Before Tax	<u>(85,973)</u>	<u>36,270</u>	<u>(57,283)</u>
Income Tax Expense (Benefit) Related to the Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(4,357)	(10,473)	1,582
Reclassification Adjustment for Income Tax Benefit Related to the Amortization of the Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	3,566	1,698	2,437
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	—	—	(15)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	2,578	20,619	(22,547)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	—	—	(158)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(25,521)	2,726	(955)
Income Tax Benefit (Expense) on Cumulative Effect of Adoption of Authoritative Guidance for Hedging	363	—	—
Reclassification Adjustment for Income Tax Benefit (Expense) on the Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities to Earnings Reinvested in the Business	—	(4,301)	—
Reclassification Adjustment for Stranded Tax Effects Related to the 2017 Tax Reform Act to Earnings Reinvested in the Business	—	10,406	—
Income Taxes — Net	<u>(23,371)</u>	<u>20,675</u>	<u>(19,656)</u>
Other Comprehensive Income (Loss)	<u>(62,602)</u>	<u>15,595</u>	<u>(37,627)</u>
Comprehensive Income (Loss)	<u><u>\$ (186,374)</u></u>	<u><u>\$ 319,885</u></u>	<u><u>\$ 353,894</u></u>

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

		At September 30	
		2020	2019
		(Thousands of dollars)	
ASSETS			
Property, Plant and Equipment	\$	12,351,852	\$ 11,204,838
Less — Accumulated Depreciation, Depletion and Amortization		6,353,785	5,695,328
		<u>5,998,067</u>	<u>5,509,510</u>
Assets Held for Sale, Net		53,424	—
Current Assets			
Cash and Temporary Cash Investments		20,541	20,428
Hedging Collateral Deposits		—	6,832
Receivables — Net of Allowance for Uncollectible Accounts of \$22,810 and \$25,788, Respectively		143,583	139,956
Unbilled Revenue		17,302	18,758
Gas Stored Underground		33,338	36,632
Materials, Supplies and Emission Allowances		51,877	40,717
Unrecovered Purchased Gas Costs		—	2,246
Other Current Assets		47,557	97,054
		<u>314,198</u>	<u>362,623</u>
Other Assets			
Recoverable Future Taxes		118,310	115,197
Unamortized Debt Expense		12,297	14,005
Other Regulatory Assets		156,106	167,320
Deferred Charges		67,131	33,843
Other Investments		154,502	144,917
Goodwill		5,476	5,476
Prepaid Post-Retirement Benefit Costs		76,035	60,517
Fair Value of Derivative Financial Instruments		9,308	48,669
Other		81	80
		<u>599,246</u>	<u>590,024</u>
Total Assets	\$	6,964,935	\$ 6,462,157
CAPITALIZATION AND LIABILITIES			
Capitalization:			
Comprehensive Shareholders' Equity			
Common Stock, \$1 Par Value; Authorized - 200,000,000 Shares; Issued and Outstanding - 90,954,696 Shares and 86,315,287 Shares, Respectively	\$	90,955	\$ 86,315
Paid In Capital		1,004,158	832,264
Earnings Reinvested in the Business		991,630	1,272,601
Accumulated Other Comprehensive Loss		(114,757)	(52,155)
Total Comprehensive Shareholders' Equity		<u>1,971,986</u>	<u>2,139,025</u>
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs		<u>2,629,576</u>	<u>2,133,718</u>
Total Capitalization		<u>4,601,562</u>	<u>4,272,743</u>
Current and Accrued Liabilities			
Notes Payable to Banks and Commercial Paper		30,000	55,200
Current Portion of Long-Term Debt		—	—
Accounts Payable		134,126	132,208
Amounts Payable to Customers		10,788	4,017
Dividends Payable		40,475	37,547
Interest Payable on Long-Term Debt		27,521	18,508
Customer Advances		15,319	13,044
Customer Security Deposits		17,199	16,210
Other Accruals and Current Liabilities		140,176	139,600
Fair Value of Derivative Financial Instruments		43,969	5,574
		<u>459,573</u>	<u>421,908</u>
Deferred Credits			
Deferred Income Taxes		696,054	653,382
Taxes Refundable to Customers		357,508	366,503
Cost of Removal Regulatory Liability		230,079	221,699
Other Regulatory Liabilities		161,573	142,367
Pension and Other Post-Retirement Liabilities		127,181	133,729
Asset Retirement Obligations		192,228	127,458
Other Deferred Credits		139,177	122,368
		<u>1,903,800</u>	<u>1,767,506</u>
Commitments and Contingencies (Note L)		—	—
Total Capitalization and Liabilities	\$	6,964,935	\$ 6,462,157

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2020	2019	2018
	(Thousands of dollars)		
Operating Activities			
Net Income (Loss) Available for Common Stock	\$ (123,772)	\$ 304,290	\$ 391,521
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Impairment of Oil and Gas Producing Properties	449,438	—	—
Depreciation, Depletion and Amortization	306,158	275,660	240,961
Deferred Income Taxes	54,313	122,265	(18,153)
Stock-Based Compensation	14,931	21,186	15,762
Other	6,527	8,608	16,133
Change in:			
Receivables and Unbilled Revenue	(2,578)	6,379	(30,882)
Gas Stored Underground and Materials, Supplies and Emission Allowances	(6,625)	(3,713)	(4,021)
Unrecovered Purchased Gas Costs	2,246	1,958	419
Other Current Assets	49,367	(29,030)	(16,519)
Accounts Payable	(4,657)	(24,770)	17,962
Amounts Payable to Customers	6,771	623	3,394
Customer Advances	2,275	(565)	(2,092)
Customer Security Deposits	989	(9,493)	5,331
Other Accruals and Current Liabilities	5,001	10,992	3,865
Other Assets	(24,203)	5,115	(9,556)
Other Liabilities	4,628	4,978	1,178
Net Cash Provided by Operating Activities	740,809	694,483	615,303
Investing Activities			
Capital Expenditures	(716,153)	(788,938)	(584,004)
Acquisition of Upstream Assets and Midstream Gathering Assets	(506,258)	—	—
Net Proceeds from Sale of Oil and Gas Producing Properties	—	—	55,506
Other	(1,205)	(10,237)	(389)
Net Cash Used in Investing Activities	(1,223,616)	(799,175)	(528,887)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	(25,200)	55,200	—
Net Proceeds from Issuance of Long-Term Debt	493,007	—	295,020
Reduction of Long-Term Debt	—	—	(566,512)
Net Proceeds from Issuance (Repurchase) of Common Stock	161,603	(8,877)	4,110
Dividends Paid on Common Stock	(153,322)	(147,418)	(143,258)
Net Cash Provided by (Used in) Financing Activities	476,088	(101,095)	(410,640)
Net Decrease in Cash, Cash Equivalents, and Restricted Cash	(6,719)	(205,787)	(324,224)
Cash, Cash Equivalents and Restricted Cash At Beginning of Year	27,260	233,047	557,271
Cash, Cash Equivalents and Restricted Cash At End of Year	\$ 20,541	\$ 27,260	\$ 233,047
Supplemental Disclosure of Cash Flow Information			
Cash Paid (Refunded) For:			
Interest	\$ 103,479	\$ 102,920	\$ 126,079
Income Taxes	\$ (82,876)	\$ (17,342)	\$ 31,771
Non-Cash Investing Activities:			
Non-Cash Capital Expenditures	\$ 87,328	\$ 81,121	\$ 88,813

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A — 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.

Regulation

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies which conform to GAAP, as applied to regulated enterprises, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. Reference is made to Note F — Regulatory Matters for further discussion.

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. In response to the COVID-19 pandemic, the Company has suspended collection and termination activity for non-payments in its Utility service territories. To date, despite the economic conditions that have arisen as a result of the COVID-19 pandemic, the Company has not experienced any meaningful change in the rate at which its customers pay their bills. To the extent the economic impacts of the COVID-19 pandemic continue into the winter heating season, the Company is anticipating that customer non-payments may increase as seasonally higher natural gas prices and usage will lead to higher costs for customers.

Regulatory Mechanisms

The Company's rate schedules in the Utility segment contain clauses that permit adjustment of revenues to reflect price changes from the cost of purchased gas included in base rates. Differences between amounts currently recoverable and actual adjustment clause revenues, as well as other price changes and pipeline and storage company refunds not yet includable in adjustment clause rates, are deferred and accounted for as either unrecovered purchased gas costs or amounts payable to customers. Such amounts are generally recovered from (or passed back to) customers during the following fiscal year.

Estimated refund liabilities to ratepayers represent management's current estimate of such refunds. Reference is made to Note F — Regulatory Matters for further discussion.

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a WNC, which covers the eight-month period from October through May. The WNC is designed to adjust the rates of retail customers to reflect the impact of deviations from normal weather. Weather that is warmer than normal results in a surcharge being added to customers' current bills, while weather that is colder than normal results in a refund being credited to customers' current bills. Since the Utility segment's Pennsylvania rate jurisdiction does not have a WNC, weather variations have a direct impact on the Pennsylvania rate jurisdiction's revenues.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The impact of weather normalized usage per customer account in the Utility segment's New York rate jurisdiction is tempered by a revenue decoupling mechanism. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. Weather normalized usage per account that exceeds the average weather normalized usage per customer account results in a refund being credited to customers' bills. Weather normalized usage per account that is below the average weather normalized usage per account results in a surcharge being added to customers' bills. The surcharge or credit is calculated over a twelve-month period ending March 31st, and applied to customer bills annually, beginning July 1st.

In the Pipeline and Storage segment, the allowed rates that Supply Corporation and Empire bill their customers are based on a straight fixed-variable rate design, which allows recovery of all fixed costs, including return on equity and income taxes, through fixed monthly reservation charges. Because of this rate design, changes in throughput due to weather variations do not have a significant impact on the revenues of Supply Corporation or Empire.

Asset Acquisition and Business Combination Accounting

In accordance with authoritative guidance issued by the FASB that clarifies the definition of a business, when the Company executes an acquisition, it will perform an initial screening test as of the acquisition date that, if met, results in the conclusion that the set of activities and assets is not a business. If the initial screening test is not met, the Company evaluates whether the set is a business based on whether there are inputs and a substantive process in place. The definition of a business impacts whether the Company consolidates an acquisition under business combination guidance or asset acquisition guidance.

When the Company acquires assets and liabilities deemed to be an asset acquisition, the fair value of the purchase consideration, including the transaction costs of the asset acquisition, is assumed to be equal to the fair value of the net assets acquired. The purchase consideration, including the transaction costs, is allocated to the individual assets and liabilities assumed based on their relative fair values. Transaction costs associated with asset acquisitions are capitalized as part of the costs of the group of assets acquired.

When the Company acquires assets and liabilities deemed to be a business combination, the acquisition method is applied. Goodwill is measured as the fair value of the consideration transferred less the net recognized fair value of the identifiable assets acquired and the liabilities assumed, all measured at the acquisition date. Transaction costs that the Company incurs in connection with a business combination, such as finders' fees, legal fees, due diligence fees and other professional and consulting fees are expensed as incurred.

Variable Interest Entity Accounting

In accordance with authoritative guidance issued by the FASB concerning a variable interest entity (VIE), the Company will evaluate a VIE to determine whether it is the primary beneficiary and therefore is considered to have a controlling financial interest. If the Company has the power to direct the activities of a VIE and the obligation to absorb significant losses of that entity or the right to receive significant benefits from that entity, the Company is considered to be the primary beneficiary and therefore consolidates that VIE into the Company's consolidated financial statements.

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

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 and \$1.7 billion at September 30, 2020 and 2019, respectively. For further discussion of capitalized costs, refer to Note O — Supplementary Information for Oil and Gas Producing Activities.

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 impairment is required to be charged to earnings in that quarter. The book value of the oil and gas properties exceeded the ceiling at September 30, 2020 as well as at June 30, 2020 and March 31, 2020. As such, the Company recognized pre-tax impairment charges of \$449.4 million for the year ended September 30, 2020. Deferred income tax benefits of \$123.1 million related to the impairment charges were also recognized for the year ended September 30, 2020. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2020, 2019 and 2018, estimated future net cash flows were increased by \$180.0 million, decreased by \$17.7 million and decreased by \$25.1 million, respectively.

The principal assets of the Utility, Pipeline and Storage and Gathering segments, consisting primarily of gas plant in service, are recorded at the historical cost when originally devoted to service. 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 September 30, 2020. Management will continue to monitor the situation on a quarterly basis.

Maintenance and repairs of property and replacements of minor items of property are charged directly to maintenance expense. The original cost of the regulated subsidiaries' property, plant and equipment retired, and the cost of removal less salvage, are charged to accumulated depreciation.

Depreciation, Depletion and Amortization

For oil and gas properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unproved oil and gas properties is excluded from this computation. Depreciation, depletion and amortization expense for oil and gas properties was \$166.8 million, \$149.9 million and \$119.9 million for the years ended September 30, 2020, 2019 and 2018, respectively. In the All Other category, for timber properties, depletion, determined on a property by property basis, has historically been charged to operations based on the actual amount of timber cut in relation to the total amount of recoverable timber. However, as discussed below in Note B — Asset Acquisitions and Divestitures, most of the Company's timber properties have been reclassified to Assets Held for Sale. The impact of that reclassification is reflected in the tables below. For all other property, plant and equipment, depreciation and amortization is computed using the straight-line method in amounts sufficient to recover costs over the estimated service lives of property in service. The following is a summary of depreciable plant by segment:

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	As of September 30	
	2020	2019
	(Thousands)	
Exploration and Production	\$ 6,384,086	\$ 5,747,731
Pipeline and Storage	2,418,265	2,191,166
Gathering	849,204	577,021
Utility	2,234,433	2,159,841
All Other and Corporate	20,372	112,857
	<u>\$ 11,906,360</u>	<u>\$ 10,788,616</u>

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2020	2019	2018
Exploration and Production, per Mcfe(1)	\$ 0.71	\$ 0.73	\$ 0.70
Pipeline and Storage	2.4 %	2.2 %	2.2 %
Gathering	3.2 %	3.6 %	3.4 %
Utility	2.7 %	2.7 %	2.8 %
All Other and Corporate	3.6 %	1.8 %	2.4 %

- (1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note O — Supplementary Information for Oil and Gas Producing Activities, depletion of oil and gas producing properties amounted to \$0.69, \$0.71 and \$0.67 per Mcfe of production in 2020, 2019 and 2018, respectively.

Goodwill

The Company has recognized goodwill of \$5.5 million as of September 30, 2020 and 2019 on its Consolidated Balance Sheets related to the Company's acquisition of Empire in 2003. The Company accounts for goodwill in accordance with the current authoritative guidance, which requires the Company to test goodwill for impairment annually. At September 30, 2020, 2019 and 2018, the fair value of Empire was greater than its book value. As such, the goodwill was not considered impaired at those dates. Going back to the origination of the goodwill in 2003, the Company has never recorded an impairment of its goodwill balance.

Financial Instruments

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of gas and oil and to manage a portion of the risk of currency fluctuations associated with transportation costs denominated in Canadian currency. These instruments include natural gas price swap agreements and no cost collars, crude oil price swap agreements, and foreign currency forward contracts. The Company accounts for these instruments as cash flow hedges for which the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled Fair Value of Derivative Financial Instruments. Reference is made to Note I — Fair Value Measurements for further discussion concerning the fair value of derivative financial instruments.

For cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues or purchased gas expense on the Consolidated Statements of Income. Reference is made to Note J — Financial Instruments for further discussion concerning cash flow hedges.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) and changes for the years ended September 30, 2020 and 2019, net of related tax effects, are as follows (amounts in parentheses indicate debits) (in thousands):

	Gains and Losses on Derivative Financial Instruments	Gains and Losses on Securities Available for Sale	Funded Status of the Pension and Other Post- Retirement Benefit Plans	Total
Year Ended September 30, 2020				
Balance at October 1, 2019	\$ 34,675	\$ —	\$ (86,830)	\$ (52,155)
Other Comprehensive Gains and Losses Before Reclassifications	7,284	—	(14,857)	(7,573)
Amounts Reclassified From Other Comprehensive Loss	(67,774)	—	11,795	(55,979)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging ..	950	—	—	950
Balance at September 30, 2020	<u>\$ (24,865)</u>	<u>\$ —</u>	<u>\$ (89,892)</u>	<u>\$ (114,757)</u>
Year Ended September 30, 2019				
Balance at October 1, 2018	\$ (28,611)	\$ 7,437	\$ (46,576)	\$ (67,750)
Other Comprehensive Gains and Losses Before Reclassifications	58,682	—	(33,616)	25,066
Amounts Reclassified From Other Comprehensive Income	2,738	—	5,634	8,372
Reclassification Adjustment for the Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities	—	(7,437)	—	(7,437)
Reclassification of Stranded Tax Effects Related to the 2017 Tax Reform Act ..	1,866	—	(12,272)	(10,406)
Balance at September 30, 2019	<u>\$ 34,675</u>	<u>\$ —</u>	<u>\$ (86,830)</u>	<u>\$ (52,155)</u>

The amounts included in accumulated other comprehensive income (loss) related to the funded status of the Company's pension and other post-retirement benefit plans consist of prior service costs and accumulated losses. The total amount for prior service cost was \$0.9 million and \$1.0 million at September 30, 2020 and 2019, respectively. The total amount for accumulated losses was \$89.0 million and \$85.8 million at September 30, 2020 and 2019, respectively.

In August 2017, the FASB issued authoritative guidance which changes the financial reporting of hedging relationships to better portray the economic results of an entity's risk management activities and to simplify the application of hedge accounting. The 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.

In February 2018, the FASB issued authoritative guidance that allows an entity to elect a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the 2017 Tax Reform Act and requires certain disclosures about stranded tax effects. The Company adopted this authoritative guidance effective January 1, 2019 and recorded a cumulative effect adjustment related to deferred income taxes associated with hedging activities and pension and post-retirement benefit obligations during the

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

quarter ended March 31, 2019 to increase retained earnings by \$10.4 million and decrease accumulated other comprehensive income by the same amount.

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

Reclassifications Out of Accumulated Other Comprehensive Income (Loss)

The details about the reclassification adjustments out of accumulated other comprehensive income (loss) for the years ended September 30, 2020 and 2019 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) for the Year Ended September 30,		Affected Line Item in the Statement Where Net Income is Presented
	2020	2019	
Gains (Losses) on Derivative Financial Instrument			
Cash Flow Hedges:			
Commodity Contracts	\$93,691	(\$3,460)	Operating Revenues
Commodity Contracts	661	(1,182)	Purchased Gas
Foreign Currency Contracts	(1,057)	(822)	Operating Revenues
Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans:			
Prior Service Cost	(237)	(264)	(1)
Net Actuarial Loss	(15,124)	(7,068)	(1)
	<u>77,934</u>	<u>(12,796)</u>	Total Before Income Tax
	<u>(21,955)</u>	<u>4,424</u>	Income Tax Expense
	<u>\$55,979</u>	<u>(\$8,372)</u>	Net of Tax

- (1) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost. Refer to Note K — Retirement Plan and Other Post-Retirement Benefits for additional details.

Gas Stored Underground

In the Utility segment, gas stored underground in the amount of \$33.2 million is carried at lower of cost or net realizable value, on a LIFO method. Based upon the average price of spot market gas purchased in September 2020, including transportation costs, the current cost of replacing this inventory of gas stored underground exceeded the amount stated on a LIFO basis by approximately \$6.6 million at September 30, 2020.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Materials, Supplies and Emission Allowances

The components of the Company's materials, supplies and emission allowances are as follows:

	Year Ended September 30	
	2020	2019
	(Thousands)	
Materials and Supplies — at average cost	\$ 33,859	\$ 29,819
Emission Allowances	18,018	10,898
	<u>\$ 51,877</u>	<u>\$ 40,717</u>

Unamortized Debt Expense

Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment. At September 30, 2020, the remaining weighted average amortization period for such costs was approximately 6 years.

Income Taxes

The Company and its subsidiaries file a consolidated federal income tax return. State tax returns are filed on a combined or separate basis depending on the applicable laws in the jurisdictions where tax returns are filed.

The Company follows the asset and liability approach in accounting for income taxes, which requires the recognition of deferred income taxes for the expected future tax consequences of net operating losses, credits and temporary differences between the financial statement carrying amounts and the tax basis of assets and liabilities. A valuation allowance is provided on deferred tax assets if it is determined, within each taxing jurisdiction, that it is more likely than not that the asset will not be realized.

The Company reports a liability or a reduction of deferred tax assets for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. When applicable, the Company recognizes interest relating to uncertain tax positions in Other Interest Expense and penalties in Other Income (Deductions).

Consolidated Statement 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):

	Year Ended September 30			
	2020	2019	2018	2017
Cash and Temporary Cash Investments	\$ 20,541	\$ 20,428	\$229,606	\$555,530
Hedging Collateral Deposits	—	6,832	3,441	1,741
Cash, Cash Equivalents, and Restricted Cash	<u>\$ 20,541</u>	<u>\$ 27,260</u>	<u>\$233,047</u>	<u>\$557,271</u>

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.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Other Current Assets

The components of the Company's Other Current Assets are as follows:

	Year Ended September 30	
	2020	2019
	(Thousands)	
Prepayments	\$ 12,851	\$ 12,728
Prepaid Property and Other Taxes	14,269	14,361
Federal Income Taxes Receivable	—	42,388
State Income Taxes Receivable	3,828	8,579
Fair Values of Firm Commitments	—	7,538
Regulatory Assets	16,609	11,460
	<u>\$ 47,557</u>	<u>\$ 97,054</u>

Other Accruals and Current Liabilities

The components of the Company's Other Accruals and Current Liabilities are as follows:

	Year Ended September 30	
	2020	2019
	(Thousands)	
Accrued Capital Expenditures	\$ 33,344	\$ 33,713
Regulatory Liabilities	44,890	50,332
Federal Income Taxes Payable	163	—
Liability for Royalty and Working Interests	15,665	18,057
Non-Qualified Benefit Plan Liability	14,460	13,194
Other	31,654	24,304
	<u>\$ 140,176</u>	<u>\$ 139,600</u>

Customer Advances

The Company, primarily in its Utility segment, has balanced billing programs whereby customers pay their estimated annual usage in equal installments over a twelve-month period. Monthly payments under the balanced billing programs are typically higher than current month usage during the summer months. During the winter months, monthly payments under the balanced billing programs are typically lower than current month usage. At September 30, 2020 and 2019, customers in the balanced billing programs had advanced excess funds of \$15.3 million and \$13.0 million, respectively.

Customer Security Deposits

The Company, primarily in its Utility and Pipeline and Storage segments, oftentimes requires security deposits from marketers, producers, pipeline companies, and commercial and industrial customers before providing services to such customers. At September 30, 2020 and 2019, the Company had received customer security deposits amounting to \$17.2 million and \$16.2 million, respectively.

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. As the Company recognized a net loss for the year ended September 30, 2020, the aforementioned securities, amounting to

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

411,890 securities, were not recognized in the diluted earnings per share calculation for 2020. For the years ended September 30, 2019 and 2018, the diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. SARs, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 242,302 securities and 317,899 securities excluded as being antidilutive for the years ended September 30, 2019 and 2018, respectively.

Stock-Based Compensation

The Company has various stock award plans which provide or provided for the issuance of one or more of the following to key employees: SARs, incentive stock options, nonqualified stock options, restricted stock, restricted stock units, performance units or performance shares. The Company follows authoritative guidance which requires the measurement and recognition of compensation cost at fair value for all share-based payments. SARs and stock options under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no SAR or stock option is exercisable less than one year or more than ten years after the date of each grant. The Company has chosen the Black-Scholes-Merton closed form model to calculate the compensation expense associated with SARs and stock options. For all Company stock awards, forfeitures are recognized as they occur.

Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. The market value of restricted stock on the date of the award is recorded as compensation expense over the vesting period. Certificates for shares of restricted stock awarded under the Company's stock award plans are held by the Company during the periods in which the restrictions on vesting are effective. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant.

Restricted stock units also are subject to restrictions on vesting and transferability. 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. The restricted stock units do not entitle the participants to dividend and voting rights. The accounting for restricted stock units is the same as the accounting for restricted stock awards, except that the fair value at the date of grant of the restricted stock units (represented by the market value of Company common stock on the date of the award) must be reduced by the present value of forgone dividends over the vesting term of the award. The fair value of restricted stock units on the date of award is recorded as compensation expense over the vesting period.

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. For performance shares based on a return on capital goal, the fair value at the date of grant of the performance shares is determined by multiplying the expected number of performance shares to be issued by the market value of Company common stock on the date of grant reduced by the present value of forgone dividends. For performance shares based on a total shareholder return goal, the Company uses the Monte Carlo simulation technique to estimate the fair value price at the date of grant.

Refer to Note H — Capitalization and Short-Term Borrowings under the heading "Stock Award Plans" for additional disclosures related to stock-based compensation awards for all plans.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Note B — Asset Acquisitions and Divestitures

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 price, which reflects an effective date of January 1, 2020, was reduced for production revenues less expenses that were retained by Shell from the effective date to the closing date. As part of the transaction, the Company acquired over 400,000 net acres in Appalachia, including approximately 200,000 net acres in Tioga County, Pennsylvania. The proved developed and undeveloped natural gas reserves associated with this acquisition amounted to 684,141 MMcf. In addition, the Company acquired gathering pipelines and related compression, water pipelines, and associated water handling infrastructure, all of which support the acquired Tioga County production operations. These gathering facilities are interconnected with various interstate pipelines, including the Company’s Empire pipeline system, with the potential to tie into the Company’s existing Covington gathering system. Post-closing, the Company has integrated the assets into its existing operations in Tioga County, which has resulted in cost synergies. This transaction was accounted for as an asset acquisition as substantially all the fair value of the gross assets acquired is concentrated in a single asset under the screen test comprised of Proved Developed Producing Reserves and the attached Gathering Property, Plant and Equipment. The purchase consideration, including the transaction costs, has been allocated to the individual assets acquired based on their relative fair values. The following is a summary of the asset acquisition (in thousands):

Purchase Price	\$ 503,908
Transaction Costs	2,350
Total Consideration	<u>\$ 506,258</u>

Allocation of Cost of Asset Acquisition:

	Exploration and Production Reporting Segment		Gathering Reporting Segment		Total
Property, Plant and Equipment	\$ 281,648	(1)(2)	\$ 223,369	(2)	\$ 505,017
Inventory	1,132		109		1,241
Total Accounting	<u>\$ 282,780</u>		<u>\$ 223,478</u>		<u>\$ 506,258</u>

- (1) Includes \$241,134 in Proved Developed Producing Properties and \$277,832 capitalized in the full cost pool.
- (2) The Company utilized an income approach and market based approach to determine the fair value of the acquired property, plant and equipment in the Exploration and Production reporting segment. The Company utilized a cost approach and an income approach to determine the fair value of the acquired property, plant and equipment in the Gathering reporting segment.

The acquisition of the upstream assets and midstream gathering assets from Shell was financed with a combination of debt and equity, as discussed in Note H — Capitalization and Short-Term Borrowings. The purchase and sale agreement with Shell was structured, in part, as a reverse like-kind exchange pursuant to Section 1031 of the Internal Revenue Code, as amended (“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 VIE formed by an exchange accommodation titleholder. A subsidiary of the Company operates the properties pursuant to a lease agreement with the VIE. As the Company is deemed to be the primary beneficiary of the VIE, it has been included in the consolidated financial statements of the Company

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

since its formation. Once the timber sale (discussed below) is completed, the affected properties will be conveyed to the Company and the VIE structure will be terminated.

On August 5, 2020, the Company entered into a purchase and sale agreement to sell substantially all timber and other assets in Pennsylvania to Lyme Emporium Highlands III LLC and Lyme Allegheny Land Company II LLC for \$115.7 million, subject to closing adjustments. The transaction is expected to close before the end of calendar 2020. The Company intends to use the proceeds from this sale to complete the Reverse 1031 Exchange discussed above. At September 30, 2020, these assets, amounting to \$53.4 million and consisting entirely of timber and other assets net of accumulated depletion, have been presented as Assets Held for Sale, Net on the Consolidated Balance Sheet. They previously were recorded as Net Property, Plant and Equipment. These assets are a component of the Company's All Other category and do not have a major impact on the Company's operations or financial results. Accordingly, the planned sale does not represent a strategic shift in focus for the Company and the financial results associated with operating these assets has not been reported as discontinued operations.

On August 1, 2020, the Company completed the sale of NFR's commercial and industrial gas contracts in New York and Pennsylvania and certain other assets to Marathon Power LLC. The sale did not have a material impact to the Company's financial statements. The divestiture reflects the Company's decision to focus on other strategic areas of the energy market.

On May 1, 2018, the Company completed the sale of its oil and gas properties in the Sespe Field area of Ventura County, California, receiving net proceeds of \$38.2 million (included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statement of Cash Flows). The divestiture of the Company's oil and gas properties in the Sespe Field reflects continuing efforts to focus West Coast development activities in the San Joaquin basin, particularly at the Midway Sunset field in Kern County, California. Under the full cost method of accounting for oil and gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

The Company also sold certain properties under a joint development agreement with IOG CRV - Marcellus, LLC that provided proceeds of \$17.3 million in fiscal 2018. These proceeds were accounted for as a reduction of capitalized costs and are included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statement of Cash Flows for fiscal 2018.

Note C — Revenue from Contracts with Customers

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

The following tables provide a disaggregation of the Company's revenues for the years ended September 30, 2020 and 2019, presented by type of service from each reportable segment.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Year Ended September 30, 2020								
Revenues by Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
(Thousands)								
Production of Natural Gas	\$ 402,447	\$ —	\$ —	\$ —	\$ 402,447	\$ —	\$ —	\$ 402,447
Production of Crude Oil	107,844	—	—	—	107,844	—	—	107,844
Natural Gas Processing	2,374	—	—	—	2,374	—	—	2,374
Natural Gas Gathering Service	—	—	142,893	—	142,893	—	(142,821)	72
Natural Gas Transportation Service	—	229,391	—	109,214	338,605	—	(77,699)	260,906
Natural Gas Storage Service	—	79,073	—	—	79,073	—	(34,579)	44,494
Natural Gas Residential Sales	—	—	—	475,846	475,846	—	—	475,846
Natural Gas Commercial Sales	—	—	—	61,239	61,239	—	—	61,239
Natural Gas Industrial Sales	—	—	—	3,291	3,291	—	—	3,291
Natural Gas Marketing	—	—	—	—	—	95,727	(835)	94,892
Other	1,097	1,140	—	(5,281)	(3,044)	5,174	(294)	1,836
Total Revenues from Contracts with Customers	513,762	309,604	142,893	644,309	1,610,568	100,901	(256,228)	1,455,241
Alternative Revenue Programs	—	—	—	7,989	7,989	—	—	7,989
Derivative Financial Instruments	93,691	—	—	—	93,691	(10,630)	—	83,061
Total Revenues	<u>\$ 607,453</u>	<u>\$ 309,604</u>	<u>\$ 142,893</u>	<u>\$ 652,298</u>	<u>\$ 1,712,248</u>	<u>\$ 90,271</u>	<u>\$ (256,228)</u>	<u>\$ 1,546,291</u>

Year Ended September 30, 2019								
Revenues by Type of Service	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
(Thousands)								
Production of Natural Gas	\$ 481,048	\$ —	\$ —	\$ —	\$ 481,048	\$ —	\$ —	\$ 481,048
Production of Crude Oil	149,078	—	—	—	149,078	—	—	149,078
Natural Gas Processing	3,277	—	—	—	3,277	—	—	3,277
Natural Gas Gathering Service	—	—	127,064	—	127,064	—	(127,064)	—
Natural Gas Transportation Service	—	209,184	—	119,253	328,437	—	(70,689)	257,748
Natural Gas Storage Service	—	75,484	—	—	75,484	—	(32,488)	42,996
Natural Gas Residential Sales	—	—	—	539,962	539,962	—	—	539,962
Natural Gas Commercial Sales	—	—	—	73,331	73,331	—	—	73,331
Natural Gas Industrial Sales	—	—	—	4,830	4,830	—	—	4,830
Natural Gas Marketing	—	—	—	—	—	143,627	(1,127)	142,500
Other	1,609	3,615	11	(8,630)	(3,395)	3,424	(549)	(520)
Total Revenues from Contracts with Customers	635,012	288,283	127,075	728,746	1,779,116	147,051	(231,917)	1,694,250
Alternative Revenue Programs	—	—	—	(1,304)	(1,304)	—	—	(1,304)
Derivative Financial Instruments	(2,272)	—	—	—	(2,272)	2,658	—	386
Total Revenues	<u>\$ 632,740</u>	<u>\$ 288,283</u>	<u>\$ 127,075</u>	<u>\$ 727,442</u>	<u>\$ 1,775,540</u>	<u>\$ 149,709</u>	<u>\$ (231,917)</u>	<u>\$ 1,693,332</u>

Exploration and Production Segment Revenue

The Company's Exploration and Production segment records revenue from the sale of the natural gas and oil that it produces and natural gas liquids (NGLs) processed based on entitlement, which means that revenue is recorded based on the actual amount of natural gas or oil that is delivered to a pipeline, or upon pick-up in the case of NGLs, and the Company's ownership interest. Natural gas production occurs primarily in the Appalachian region of the United States and crude oil production occurs primarily in the West Coast region of

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

the United States. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance. The sales contracts generally require the Company to deliver a specific quantity of a commodity per day for a specific number of days at a price that is either fixed or variable and considers the delivery of each unit (MMBtu or Bbl) to be a separate performance obligation that is satisfied upon delivery.

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

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

Pipeline and Storage Segment Revenue

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

The Company’s Pipeline and Storage segment expects to recognize the following revenue amounts in future periods related to “fixed” charges associated with remaining performance obligations for transportation and storage contracts: \$185.2 million for fiscal 2021; \$163.7 million for fiscal 2022; \$132.4 million for fiscal 2023; \$123.0 million for fiscal 2024; \$116.7 million for fiscal 2025; and \$517.4 million thereafter.

Gathering Segment Revenue

The Company’s Gathering segment provides gathering and processing services in the Appalachian region of Pennsylvania, primarily for Seneca. The Gathering segment’s primary performance obligation is to deliver gathered natural gas volumes from Seneca’s wells into interstate pipelines at contractually agreed upon per unit rates. This obligation is satisfied over time. The performance obligation is satisfied based on the passage of

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

time and meter reads, which correlates to the period for which the charges are eligible to be invoiced. The amount billable, as determined by the meter read and the contracted volumetric rate, indicates the value to the customer, and is used for revenue recognition purposes by the Gathering segment as specified by the “invoice practical expedient” (the amount that the Gathering segment has the right to invoice) under the authoritative guidance for revenue recognition. Customers are billed after the end of each calendar month, with payment typically due by the 10th day after the invoice is received.

Utility Segment Revenue

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

Utility Segment Alternative Revenue Programs

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

Energy Marketing Revenue

The Company’s energy marketing subsidiary, NFR (included in the All Other category), which records revenue from natural gas sales in western and central New York and northwestern Pennsylvania, completed the sale of its commercial and industrial contracts and certain other assets on August 1, 2020 and is winding down its operations. The Company does not report NFR’s energy marketing operations as a separate reportable segment. NFR’s sales have been provided largely to industrial, wholesale, commercial, public authority and

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

residential customers. NFR's performance obligation to its customers has been to deliver natural gas, an obligation which is satisfied over time. This obligation generally remains in effect as long as the customer consumes the natural gas provided by NFR. NFR recognizes revenue when it satisfies its performance obligation by delivering natural gas to the customer. Natural gas is delivered and consumed by the customer simultaneously. The satisfaction of the performance obligation is measured by the turn of the meter dial. The amount billable, as determined by the meter read and the contracted or market based rate, indicates the value to the customer, and is used for revenue recognition purposes by NFR as specified by the "invoice practical expedient" (the amount that NFR has the right to invoice) under the authoritative guidance for revenue recognition.

The Company used derivative financial instruments through August 1, 2020 to manage commodity price risk in its NFR operations related to the sale of natural gas to its customers. Gains or losses on such derivative financial instruments were recorded as adjustments to revenue; however, they were not considered to be revenue from contracts with customers.

Note D — Leases

On October 1, 2019, the Company adopted authoritative guidance regarding lease accounting, which requires entities that lease the use of property, plant and equipment to recognize on the balance sheet the assets and liabilities for the rights and obligations created by all leases, including leases classified as operating leases. The Company implemented the new standard using the optional transition method and elected to apply the following practical expedients provided in the authoritative guidance:

1. For contracts that commenced prior to and existed as of October 1, 2019, a package of practical expedients to not reassess whether a contract is or contains a lease, lease classification, and initial direct costs under the new authoritative guidance;
2. An election not to apply the recognition requirements in the new authoritative guidance to short-term leases (a lease that at commencement date has a lease term of one year or less);
3. A practical expedient to not reassess certain land easements that existed prior to October 1, 2019 and were not previously accounted for as leases under the prior authoritative guidance; and
4. A practical expedient that permits combining lease and non-lease components in a contract and accounting for the combination as a lease (elected by asset-class).

Upon adoption, the Company increased assets and liabilities on its Consolidated Balance Sheet by \$19.7 million. The adoption did not result in a cumulative effect adjustment to earnings reinvested in the business or have a material impact on the Company's Consolidated Statement of Income or Consolidated Statement of Cash Flows. Comparative periods, including disclosures relating to those periods, were not restated.

Nature of Leases

The Company primarily leases building space and drilling rigs, and on a limited basis compressor equipment and other miscellaneous assets. The Company determines if an arrangement is a lease at the inception of the arrangement. To the extent that an arrangement represents a lease, the Company classifies that lease as an operating or a finance lease in accordance with the authoritative guidance. As of September 30, 2020, the Company did not have any material finance leases. Aside from a sublease of office space at the Company's corporate headquarters, the Company does not have any material arrangements where the Company is the lessor.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Buildings and Property

The Company enters into building and property rental agreements with third parties for office space, certain field locations and other properties used in the Company's operations. Building and property leases include the Company's corporate headquarters in Williamsville, New York, and Exploration and Production segment offices in Houston, Texas, and Pittsburgh, Pennsylvania. The primary non-cancelable terms of the Company's building and property leases range from one month to ten years. Most building leases include one or more options to renew, generally at the Company's sole discretion, with renewal terms that can extend the lease terms from one year to fourteen years. Renewal options are included in the lease term if they are reasonably certain to be exercised. The agreements do not contain any material restrictive covenants.

In March 2020, the Company entered into a lease agreement that commenced in November 2020. This lease agreement is a building and property lease for a term of ten years. Total estimated base rent payments over the lease term are approximately \$8.4 million. There is also an option to extend the term of the lease for one additional period of eighteen months.

Drilling Rigs

The Company enters into contracts for drilling rig services with third party contractors to support Seneca's development activities in Pennsylvania and California. Seneca's drilling rig arrangements are structured with a non-cancelable primary term of one year or less. Upon mutual agreement with the contractor, Seneca has the option to extend the contract with amended terms and conditions, including a renegotiated day rate fee.

The Company has strategically entered into shorter-term drilling rig arrangements to allow for operational and financial flexibility to respond to changes in its operating and economic environment. The Company uses discretion in choosing to extend or not extend drilling rig contracts on a rig by rig basis depending on market and operating conditions present at the time the contract expires, including prices for natural gas and oil and other performance indicators.

Due to these considerations, the Company concluded that it is not reasonably certain that it will elect to extend any of its drilling rig arrangements beyond their primary non-cancelable terms of one year or less. Consequently, the Company's drilling rig leases are deemed to be short-term leases subject to the exemption for balance sheet recognition. These costs are capitalized as part of oil and natural gas properties on the Consolidated Balance Sheet when incurred.

Significant Judgments

Lease Identification

The Company uses judgment when determining whether or not an arrangement is or contains a lease. A contract is or contains a lease if the contract conveys the right to use an explicitly or implicitly identified asset that is physically distinct and the Company has the right to control the use of the identified asset for a period of time. When determining right of control, the Company evaluates whether it directs the use of the asset and obtains substantially all of the economic benefits from the use of the asset.

Discount Rate

The Company uses a discount rate to calculate the present value of lease payments in order to determine lease classification and measurement of the lease asset and liability. In the absence of a rate of interest that is readily determinable in the contract, the Company estimates the incremental borrowing rate (IBR) for each lease. The IBR reflects the rate of interest that the Company would pay on the lease commencement date to borrow an amount equal to the lease payments on a collateralized basis over a similar term in similar economic environments.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Firm Transportation and Storage Contracts

The Company's subsidiaries enter into long-term arrangements to both reserve firm transportation capacity on third party pipelines and provide firm transportation and storage services to third party shippers. The Company's firm capacity contracts with non-affiliated entities do not provide rights to use substantially all of the underlying pipeline or storage asset. As such, the Company has concluded that these arrangements are not leases under the authoritative guidance.

Oil and Gas Leases

The new authoritative guidance does not apply to leases to explore for or use minerals, oil or natural gas resources, including the right to explore for those natural resources and rights to use the land in which those natural resources are contained. As such, the Company has concluded that its oil and gas exploration and production leases and gas storage leases are not leases under the authoritative guidance.

Amounts Recognized in the Financial Statements

Operating lease costs, excluding those relating to short-term drilling rig leases that are capitalized as part of oil and natural gas properties under full cost pool accounting, are presented in Operations and Maintenance expense on the Consolidated Statement of Income. The following table summarizes the components of the Company's total operating lease costs (in thousands):

	Year Ended September 30, 2020
Operating Lease Expense	\$ 4,129
Variable Lease Expense(1)	525
Short-Term Lease Expense(2)	918
Sublease Income	(297)
Total Lease Expense	<u>\$ 5,275</u>
Short-Term Lease Costs Recorded to Property, Plant and Equipment(3)	<u>\$ 19,232</u>

- (1) Variable lease payments that are not dependent on an index or rate are not included in the lease liability.
(2) Short-term lease costs exclude expenses related to leases with a lease term of one month or less.
(3) Short-term lease costs relating to drilling rig leases that are capitalized as part of oil and natural gas properties under full cost pool accounting.

Right-of-use assets and lease liabilities are recognized at the commencement date of a leasing arrangement based on the present value of lease payments over the lease term. As of September 30, 2020, the weighted average remaining lease term was 7.4 years and the weighted average discount rate was 3.39%.

The Company's right-of-use operating lease assets are reflected as Deferred Charges on the Consolidated Balance Sheet. The corresponding operating lease liabilities are reflected in Other Accruals and Current Liabilities (current) and Other Deferred Credits (noncurrent). Short-term leases that have a lease term of one year or less are not recorded on the Consolidated Balance Sheet.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The following amounts related to operating leases were recorded on the Company's Consolidated Balance Sheet (in thousands):

	<u>At September 30, 2020</u>
Assets:	
Deferred Charges	\$ 19,850
Liabilities:	
Other Accruals and Current Liabilities	\$ 4,943
Other Deferred Credits	\$ 14,777

For the year ended September 30, 2020, cash paid for lease liabilities, and reported in cash flows provided by operating activities on the Company's Consolidated Statement of Cash Flows, was \$5.3 million. During the year ended September 30, 2020, the Company did not record any right-of-use assets in exchange for new lease liabilities.

The following schedule of operating lease liability maturities summarizes the undiscounted lease payments owed by the Company to lessors pursuant to contractual agreements in effect as of September 30, 2020 (in thousands):

	<u>At September 30, 2020</u>
2021	\$ 4,968
2022	3,045
2023	2,507
2024	2,238
2025	2,086
Thereafter	7,631
Total Lease Payments	22,475
Less: Interest	(2,755)
Total Lease Liability	\$ 19,720

The future minimum operating lease payments as of September 30, 2019, as reported in the Company's 2019 Form 10-K, under the prior authoritative guidance are as follows (in thousands):

	<u>At September 30, 2019</u>
2020(1)	\$ 12,356
2021	2,813
2022	2,264
2023	2,270
2024	2,237
Thereafter	9,717
Total Operating Lease Obligations	\$ 31,657

- (1) The future minimum operating lease payment amount for 2020 includes short-term leases, including drilling rigs, that are not included in the schedule of operating lease liability maturities above under the new authoritative guidance.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Note E — Asset Retirement Obligations

The Company accounts for asset retirement obligations in accordance with the authoritative guidance that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. An asset retirement obligation is defined as a legal obligation associated with the retirement of a tangible long-lived asset in which the timing and/or method of settlement may or may not be conditional on a future event that may or may not be within the control of the Company. When the liability is initially recorded, the entity capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. The Company estimates the fair value of its asset retirement obligations based on the discounting of expected cash flows using various estimates, assumptions and judgments regarding certain factors such as the existence of a legal obligation for an asset retirement obligation; estimated amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 fair value measurements as the inputs used to measure the fair value are unobservable.

The Company has recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and has capitalized such costs in property, plant and equipment (i.e. the full cost pool).

In addition to the asset retirement obligation recorded in the Exploration and Production segment, the Company has recorded future asset retirement obligations associated with the plugging and abandonment of natural gas storage wells in the Pipeline and Storage segment and the removal of asbestos and asbestos-containing material in various facilities in the Utility and Pipeline and Storage segments. The Company has also recorded asset retirement obligations for certain costs connected with the retirement of the distribution mains, services and other components of the pipeline system in the Utility segment, the transmission mains and other components in the pipeline system in the Pipeline and Storage segment, and the gathering lines and other components in the Gathering segment. The retirement costs within the distribution, transmission and gathering systems are primarily for the capping and purging of pipe, which are generally abandoned in place when retired, as well as for the clean-up of PCB contamination associated with the removal of certain pipe.

As discussed in Note B — Asset Acquisitions and Divestitures, on July 31, 2020, the Company completed its acquisition of certain upstream assets and midstream gathering assets in Pennsylvania from Shell. With the acquisition of these assets, the Company recorded an additional \$57.2 million to its Asset Retirement Obligations at September 30, 2020, which is reflected in Liabilities Incurred in the table below. The following is a reconciliation of the change in the Company's asset retirement obligations:

	Year Ended September 30		
	2020	2019	2018
	(Thousands)		
Balance at Beginning of Year	\$ 127,458	\$ 108,235	\$ 106,395
Liabilities Incurred	61,246	4,122	5,597
Revisions of Estimates	3,267	16,693	(419)
Liabilities Settled	(7,268)	(7,670)	(12,858)
Accretion Expense	7,525	6,078	9,520
Balance at End of Year	<u>\$ 192,228</u>	<u>\$ 127,458</u>	<u>\$ 108,235</u>

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Note F — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2020	2019
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note K)	\$ 107,010	\$ 114,509
Post-Retirement Benefit Costs(2) (Note K)	18,863	18,236
Recoverable Future Taxes (Note G)	118,310	115,197
Environmental Site Remediation Costs(2) (Note L)	10,479	15,317
Asset Retirement Obligations(2) (Note E)	16,245	15,696
Unamortized Debt Expense (Note A)	12,297	14,005
Other(3)	20,118	15,022
Total Regulatory Assets	303,322	307,982
Less: Amounts Included in Other Current Assets	(16,609)	(11,460)
Total Long-Term Regulatory Assets	<u>\$ 286,713</u>	<u>\$ 296,522</u>
	At September 30	
	2020	2019
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	\$ 230,079	\$ 221,699
Taxes Refundable to Customers (Note G)	357,508	366,503
Post-Retirement Benefit Costs(4) (Note K)	146,474	126,577
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	10,788	4,017
Other(5)	59,989	66,122
Total Regulatory Liabilities	804,838	784,918
Less: Amounts included in Current and Accrued Liabilities	(55,678)	(54,349)
Total Long-Term Regulatory Liabilities	<u>\$ 749,160</u>	<u>\$ 730,569</u>

- (1) The Company recovers the cost of its regulatory assets but generally does not earn a return on them. There are a few exceptions to this rule. For example, the Company does earn a return on Unrecovered Purchased Gas Costs and, in the New York jurisdiction of its Utility segment, earns a return, within certain parameters, on the excess of cumulative funding to the pension plan over the cumulative amount collected in rates.
- (2) Included in Other Regulatory Assets on the Consolidated Balance Sheets.
- (3) \$16,609 and \$11,460 are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2020 and 2019, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. \$3,509 and \$3,562 are included in Other Regulatory Assets on the Consolidated Balance Sheets at September 30, 2020 and 2019, respectively.
- (4) Included in Other Regulatory Liabilities on the Consolidated Balance Sheets.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

- (5) \$44,890 and \$50,332 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2020 and 2019, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. \$15,099 and \$15,790 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2020 and 2019, respectively.

If for any reason the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the Consolidated Balance Sheets and included in income of the period in which the discontinuance of regulatory accounting treatment occurs.

Cost of Removal Regulatory Liability

In the Company's Utility and Pipeline and Storage segments, costs of removing assets (i.e. asset retirement costs) are collected from customers through depreciation expense. These amounts are not a legal retirement obligation as discussed in Note E — Asset Retirement Obligations. Rather, they are classified as a regulatory liability in recognition of the fact that the Company has collected dollars from the customer that will be used in the future to fund asset retirement costs.

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.

Pennsylvania Jurisdiction

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

FERC Jurisdiction

Supply Corporation's recent 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 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 no party may make a filing for new rates before March 31, 2021. If no rate case has been filed, Empire must make a rate case filing no later than May 1, 2025.

Note G — Income Taxes

On December 22, 2017, federal tax legislation referred to as the "Tax Cuts and Jobs Act" (the 2017 Tax Reform Act) was enacted. The 2017 Tax Reform Act significantly changed the taxation of business entities and includes a reduction in the corporate federal income tax rate from 35% to 21% for fiscal 2019 and beyond. Since the Company is a fiscal year taxpayer, the Company was subject to a blended rate of 24.5% for fiscal 2018. The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes are to be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds or surcharges of other deferred income taxes will be determined by the federal and state regulatory agencies.

The 2017 Tax Reform Act also repealed the corporate alternative minimum tax (AMT) and provides that the Company's existing AMT credit carryovers are refundable, if not utilized to reduce tax, beginning in fiscal 2019. As of September 30, 2018, the Company had \$85.0 million of AMT credit carryovers. The Company received the first installment for \$42.5 million of AMT credit refunds related to fiscal 2019 in January 2020. On

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

March 27, 2020, the “Coronavirus Aid, Relief and Economic Security (CARES) Act” was signed into law. The CARES Act, among other things, includes provisions relating to AMT credit refunds discussed above, refundable payroll tax credits, deferment of employer side social security payments, net operating loss carryback periods, and modifications to the net interest deduction limitation. The Company filed for the acceleration of the remaining AMT credit refunds (under CARES) of \$42.5 million, which were received in June 2020.

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

	Year Ended September 30		
	2020	2019	2018
	(Thousands)		
Current Income Taxes —			
Federal	\$ (42,548)	\$ (41,645)	\$ 2,025
State	6,974	4,601	8,634
Deferred Income Taxes —			
Federal	4,538	98,514	(38,927)
State	49,775	23,751	20,774
	18,739	85,221	(7,494)
Deferred Investment Tax Credit	(13)	(91)	(105)
Total Income Taxes	<u>\$ 18,726</u>	<u>\$ 85,130</u>	<u>\$ (7,599)</u>
Presented as Follows:			
Other (Income) Deductions	\$ (13)	\$ (91)	\$ (105)
Income Tax Expense (Benefit)	18,739	85,221	(7,494)
Total Income Taxes	<u>\$ 18,726</u>	<u>\$ 85,130</u>	<u>\$ (7,599)</u>

Total income taxes as reported differ from the amounts that were computed by applying the federal income tax rate to income before income taxes. The following is a reconciliation of this difference:

	Year Ended September 30		
	2020	2019	2018
	(Thousands)		
U.S. Income (Loss) Before Income Taxes	<u>\$ (105,046)</u>	<u>\$ 389,420</u>	<u>\$ 383,922</u>
Income Tax Expense, Computed at			
U.S. Federal Statutory Rate(1)	\$ (22,060)	\$ 81,778	\$ 94,061
State Valuation Allowance(2)	63,205	—	—
State Income Tax (3)	(18,374)	22,397	22,203
Amortization of Excess Deferred Federal Income Taxes(4)	(4,749)	(3,185)	(1,336)
Plant Flow Through Items	(2,848)	(1,544)	(872)
Stock Compensation	3,867	(1,491)	(321)
Federal Tax Credits	(217)	(7,361)	(6,576)
Impact of 2017 Tax Reform Act(5)	—	(5,000)	(112,598)
Miscellaneous	(98)	(464)	(2,160)
Total Income Taxes	<u>\$ 18,726</u>	<u>\$ 85,130</u>	<u>\$ (7,599)</u>

- (1) For fiscal 2020 and 2019, the statutory rate of 21% was utilized. For fiscal 2018, a blended rate of 24.5% was utilized, calculated as 35% for the first quarter of the fiscal year and 21% for the remaining three quarters.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

- (2) During fiscal 2020, a valuation allowance was recorded against certain state deferred tax assets, as discussed below.
- (3) The state income tax expense (benefit) shown above includes the impact of state enhanced oil recovery tax credits and adjustments to the estimated state effective tax rates utilized in the calculation of deferred income taxes.
- (4) Represents amortization of net excess deferred federal income taxes under the 2017 Tax Reform Act.
- (5) The \$5.0 million benefit in fiscal 2019 represents the reversal of the estimated sequestration of AMT credit refunds. The amount for fiscal 2018 represents the remeasurement of deferred income taxes as a result of the lower U.S. corporate income tax rate, including a \$5.0 million estimate for the potential sequestration of AMT credit refunds and the benefit of \$9.1 million as a result of the blended tax rate.

Significant components of the Company's deferred tax liabilities and assets were as follows:

	At September 30	
	2020	2019
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	\$ 874,607	\$ 861,278
Pension and Other Post-Retirement Benefit Costs	54,066	55,795
Other	23,377	54,486
Total Deferred Tax Liabilities	<u>952,050</u>	<u>971,559</u>
Deferred Tax Assets:		
Tax Loss and Credit Carryforwards	(179,363)	(175,542)
Pension and Other Post-Retirement Benefit Costs	(95,599)	(87,280)
Other	(44,239)	(55,355)
Total Gross Deferred Tax Assets	<u>(319,201)</u>	<u>(318,177)</u>
Valuation Allowance	63,205	—
Total Deferred Tax Assets	<u>(255,996)</u>	<u>(318,177)</u>
Total Net Deferred Income Taxes	<u>\$ 696,054</u>	<u>\$ 653,382</u>

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 \$63.2 million as of September 30, 2020 as a result of certain current year 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.

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to \$357.5 million and \$366.5 million at September 30, 2020 and 2019, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of ratemaking practices, amounted to \$118.3 million and \$115.2 million at September 30, 2020 and 2019, respectively.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The following is a reconciliation of the change in unrecognized tax benefits:

	Year Ended September 30		
	2020	2019	2018
	(Thousands)		
Balance at Beginning of Year	\$ —	\$ —	\$ 1,251
Additions for Tax Positions of Prior Years	—	—	—
Reductions for Tax Positions of Prior Years	—	—	(788)
Reductions Related to Settlements with Taxing Authorities	—	—	(463)
Balance at End of Year	<u>\$ —</u>	<u>\$ —</u>	<u>\$ —</u>

The IRS is currently conducting an examination of the Company for fiscal 2020 in accordance with the Compliance Assurance Process (“CAP”). The CAP audit employs a real time review of the Company’s books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. The federal statute of limitations remains open for fiscal 2017 and later years. The Company is also subject to various routine state income tax examinations. The Company’s principal subsidiaries operate mainly in four states which have statutes of limitations that generally expire between three to four years from the date of filing of the income tax return. Net operating losses being carried forward from prior years remain subject to examination on a future return until they are utilized, upon which time the statute of limitation begins.

During fiscal 2009, preliminary consent was received from the IRS National Office approving the Company’s application to change its tax method of accounting for certain capitalized costs relating to its utility property, subject to final guidance. The Company is awaiting the issuance of IRS guidance addressing the issue for natural gas utilities.

Tax carryforwards available, prior to valuation allowance, at September 30, 2020, were as follows:

Jurisdiction	Tax Attribute	Amount (Thousands)	Expires
Federal Pre-Fiscal 2019	Net Operating Loss	\$ 205,918	2032-2038
Federal Post-Fiscal 2018	Net Operating Loss	185,779	Unlimited
Pennsylvania	Net Operating Loss	428,672	2031-2041
California	Net Operating Loss	224,159	2031-2041
Federal	Enhanced Oil Recovery Credit	26,790	2029-2039
California	Enhanced Oil Recovery Credit	8,502	2037-2039
California	Alternative Minimum Tax Credit	8,864	Unlimited
Federal	R&D Tax Credit	6,550	2031-2040
Federal	Charitable Contributions	1,559	2025

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Note H — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	<u>Common Stock</u>		<u>Paid In</u>	<u>Earnings</u>	<u>Accumulated</u>
	<u>Shares</u>	<u>Amount</u>	<u>Capital</u>	<u>Reinvested</u>	<u>Other</u>
				<u>in the</u>	<u>Comprehensive</u>
				<u>Business</u>	<u>Income (Loss)</u>
	(Thousands, except per share amounts)				
Balance at September 30, 2017	85,543	\$85,543	\$ 796,646	\$ 851,669	\$ (30,123)
Net Income Available for Common Stock ..				391,521	
Dividends Declared on Common Stock (\$1.68 Per Share)				(144,290)	
Other Comprehensive Loss, Net of Tax					(37,627)
Share-Based Payment Expense(1)			14,235		
Common Stock Issued Under Stock and Benefit Plans	414	414	9,342		
Balance at September 30, 2018	<u>85,957</u>	<u>85,957</u>	<u>820,223</u>	<u>1,098,900</u>	<u>(67,750)</u>
Net Income Available for Common Stock ..				304,290	
Dividends Declared on Common Stock (\$1.72 Per Share)				(148,432)	
Cumulative Effect of Adoption of Authoritative Guidance for Financial Assets and Liabilities				7,437	
Cumulative Effect of Adoption of Authoritative Guidance for Reclassification of Stranded Tax Effects ..				10,406	
Other Comprehensive Income, Net of Tax ..					15,595
Share-Based Payment Expense(1)			19,613		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	358	358	(7,572)		
Balance at September 30, 2019	<u>86,315</u>	<u>86,315</u>	<u>832,264</u>	<u>1,272,601</u>	<u>(52,155)</u>
Net Loss Available for Common Stock				(123,772)	
Dividends Declared on Common Stock (\$1.76 Per Share)				(156,249)	
Cumulative Effect of Adoption of Authoritative Guidance for Hedging				(950)	
Other Comprehensive Loss, Net of Tax					(62,602)
Share-Based Payment Expense(1)			13,180		
Common Stock Issued from Sale of Common Stock	4,370	4,370	161,399		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	270	270	(2,685)		
Balance at September 30, 2020	<u>90,955</u>	<u>\$90,955</u>	<u>\$1,004,158</u>	<u>\$ 991,630</u>	<u>(2) \$ (114,757)</u>

(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.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

- (2) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2020, \$848.4 million of accumulated earnings was free of such limitations.

Common Stock

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. Refer to Note B – Asset Acquisitions and Divestitures for further discussion.

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends and make cash investments in the Company's common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, at the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent. During 2020, the Company did not issue any original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan or the Company's 401(k) plans.

During 2020, the Company issued 87,835 original issue shares of common stock for restricted stock units that vested and 231,246 original issue shares of common stock for performance shares that vested. Holders of stock-based compensation awards will often tender shares of common stock to the Company for payment of applicable withholding taxes. During 2020, 91,545 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.

The Company also has a director stock program under which it issues shares of Company common stock to the non-employee directors of the Company who receive compensation under the Company's 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors' services during the fiscal year. Under this program, the Company issued 41,873 original issue shares of common stock during 2020.

Stock Award Plans

The Company has various stock award plans which provide or provided for the issuance of one or more of the following to key employees: SARs, incentive stock options, nonqualified stock options, restricted stock, restricted stock units, performance units or performance shares.

Stock-based compensation expense for the years ended September 30, 2020, 2019 and 2018 was approximately \$13.1 million, \$19.5 million and \$14.2 million, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statements of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2020, 2019 and 2018 was approximately \$2.1 million, \$3.8 million and \$3.4 million, respectively. A portion of stock-based compensation expense is subject to capitalization under IRS uniform capitalization rules. Stock-based compensation of \$0.1 million was capitalized under these rules during each of the years ended September 30, 2020, 2019 and 2018. The tax expense related to stock-based compensation exercises and vestings was \$3.2 million for the year ended September 30, 2020.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

SARs

Transactions for 2020 involving SARs for all plans are summarized as follows:

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2019	733,132	\$ 54.90		
Granted in 2020	—	\$ —		
Exercised in 2020	—	\$ —		
Forfeited in 2020	—	\$ —		
Expired in 2020	(219,952)	\$ 52.18		
Outstanding at September 30, 2020	513,180	\$ 56.07	1.28	\$ —
SARs exercisable at September 30, 2020	513,180	\$ 56.07	1.28	\$ —
Shares available for future grant at September 30, 2020(1)	3,220,528			

(1) Includes shares available for options, SARs, restricted stock and performance share grants.

The Company did not grant any SARs during the years ended September 30, 2019 and 2018. The Company's SARs include both performance based and nonperformance-based SARs, but the performance conditions associated with the performance based SARs at the time of grant have all been subsequently met. The SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for SARs is the same as the accounting for stock options.

The total intrinsic value of SARs exercised during the years ended September 30, 2019 and 2018 totaled approximately \$7.2 million, and \$4.4 million, respectively. There were no SARs that became fully vested during the years ended September 30, 2020, 2019 and 2018, and all SARs outstanding have been fully vested since fiscal 2017.

Restricted Share Awards

Transactions for 2020 involving restricted share awards for all plans are summarized as follows:

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Outstanding at September 30, 2019	20,000	\$ 47.46
Granted in 2020	—	\$ —
Vested in 2020	—	\$ —
Forfeited in 2020	—	\$ —
Outstanding at September 30, 2020	20,000	\$ 47.46

The Company did not grant any restricted share awards (non-vested stock as defined by the current accounting literature) during the years ended September 30, 2019 and 2018. As of September 30, 2020, unrecognized compensation expense related to restricted share awards totaled less than \$0.1 million, which will be recognized over a weighted average period of 0.1 years.

Vesting restrictions for the 20,000 outstanding shares of non-vested restricted stock at September 30, 2020 will lapse in 2021.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Restricted Stock Units

Transactions for 2020 involving nonperformance-based restricted stock units for all plans are summarized as follows:

	Number of Restricted Stock Units	Weighted Average Fair Value per Award
Outstanding at September 30, 2019	281,607	\$ 48.88
Granted in 2020	150,839	\$ 40.38
Vested in 2020	(87,835)	\$ 50.26
Forfeited in 2020	(8,838)	\$ 46.72
Outstanding at September 30, 2020	<u>335,773</u>	<u>\$ 44.76</u>

The Company also granted 123,939 and 89,672 nonperformance-based restricted stock units during the years ended September 30, 2019 and 2018, respectively. The weighted average fair value of such nonperformance-based restricted stock units granted in 2019 and 2018 was \$49.40 per share and \$51.23 per share, respectively. As of September 30, 2020, unrecognized compensation expense related to nonperformance-based restricted stock units totaled approximately \$6.3 million, which will be recognized over a weighted average period of 2.1 years.

Vesting restrictions for the nonperformance-based restricted stock units outstanding at September 30, 2020 will lapse as follows: 2021 — 105,960 units; 2022 — 97,870 units; 2023 — 82,373 units; 2024 - 32,570 units; and 2025 - 17,000 units.

Performance Shares

Transactions for 2020 involving performance shares for all plans are summarized as follows:

	Number of Performance Shares	Weighted Average Fair Value per Award
Outstanding at September 30, 2019	522,514	\$ 54.37
Granted in 2020	254,608	\$ 43.32
Vested in 2020	(231,246)	\$ 55.33
Forfeited in 2020	(11,040)	\$ 46.40
Change in Units Based on Performance Achieved	57,792	\$ 52.13
Outstanding at September 30, 2020	<u>592,628</u>	<u>\$ 49.18</u>

The Company also granted 244,734 and 208,588 performance shares during the years ended September 30, 2019 and 2018, respectively. The weighted average grant date fair value of such performance shares granted in 2019 and 2018 was \$55.67 per share and \$50.95 per share, respectively. As of September 30, 2020, unrecognized compensation expense related to performance shares totaled approximately \$10.6 million, which will be recognized over a weighted average period of 1.7 years. Vesting restrictions for the outstanding performance shares at September 30, 2020 will lapse as follows: 2021 — 169,912 shares; 2022 — 176,160 shares; and 2023 — 246,556 shares.

Half of the performance shares granted during the years ended September 30, 2020, 2019 and 2018 must meet a performance goal related to relative return on capital over a three-year performance cycle. The performance goal over the respective performance cycles for the performance shares granted during 2020, 2019 and 2018 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

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 years ended September 30, 2020, 2019 and 2018 must meet a performance goal related to relative total shareholder return over a three-year performance cycle. The performance goal over the respective performance cycles for the total shareholder return performance shares ("TSR performance shares") granted during 2020, 2019 and 2018 is the Company's three-year total shareholder return relative to the three-year total shareholder return of the other companies in the Report Group. Three-year shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company's securities at each ex-dividend date) in the Bloomberg database. The number of these 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. In calculating the fair value of the award, the risk-free interest rate is based on the yield of a Treasury Note with a term commensurate with the remaining term of the TSR performance shares. The remaining term is based on the remainder of the performance cycle as of the date of grant. The expected volatility is based on historical daily stock price returns. For the TSR performance shares, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees. The following assumptions were used in estimating the fair value of the TSR performance shares at the date of grant:

	Year Ended September 30		
	2020	2019	2018
Risk-Free Interest Rate	1.63 %	2.61 %	1.96 %
Remaining Term at Date of Grant (Years)	2.81	2.78	2.78
Expected Volatility	19.3 %	20.2 %	22.0 %
Expected Dividend Yield (Quarterly)	N/A	N/A	N/A

Redeemable Preferred Stock

As of September 30, 2020, there were 10,000,000 shares of \$1 par value Preferred Stock authorized but unissued.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Long-Term Debt

The outstanding long-term debt is as follows:

	At September 30	
	2020	2019
	(Thousands)	
Medium-Term Notes(1):		
7.4% due March 2023 to June 2025	\$ 99,000	\$ 99,000
Notes(1)(2)(3):		
3.75% to 5.50% due December 2021 to September 2028	2,550,000	2,050,000
Total Long-Term Debt	2,649,000	2,149,000
Less Unamortized Discount and Debt Issuance Costs	19,424	15,282
Less Current Portion(4)	—	—
	<u>\$ 2,629,576</u>	<u>\$ 2,133,718</u>

- (1) The Medium-Term Notes and Notes are unsecured.
- (2) The holders of these 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.
- (3) The interest rate payable on \$300.0 million of 4.75% notes and \$300.0 million of 3.95% notes will be subject to adjustment from time to time, with a maximum 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 to below investment grade (or if the credit rating assigned to the notes is subsequently upgraded). The interest rate payable on \$500.0 million of 5.50% notes will be subject to a maximum adjustment of 2.00% such that the coupon will not exceed 7.5% 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.
- (4) None of the Company's long-term debt at September 30, 2020 and 2019 will mature within the following twelve-month period.

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 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.

On August 17, 2018, the Company issued \$300.0 million of 4.75% notes due September 1, 2028. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to \$295.0 million. The proceeds of this debt issuance were used for general corporate purposes, including the redemption of \$250.0 million of 8.75% notes on September 7, 2018 that were scheduled to mature in May 2019. The Company redeemed those notes for \$259.5 million, plus accrued interest. In the Utility and Pipeline and Storage segments, the call premium of \$8.5 million was recorded to Unamortized Debt Expense on the Consolidated Balance Sheet as of September 30, 2018, and in the Exploration and Production segment, the call premium of \$1.0 million was recorded to Interest Expense on Long-Term Debt on the Consolidated Income Statement during the year ended September 30, 2018.

The Company redeemed \$300.0 million of 6.50% notes in October 2017 that were scheduled to mature in April 2018. The Company redeemed these notes for \$307.0 million, plus accrued interest. The early redemption

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

premium was recorded to Unamortized Debt Expense on the Consolidated Balance Sheet in October 2017. The Company financed this redemption with proceeds from its September 27, 2017 issuance of \$300.0 million of 3.95% notes due September 15, 2027.

As of September 30, 2020, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: zero in 2021, \$500.0 million in 2022, \$549.0 million in 2023, zero in 2024, \$500.0 million in 2025, and \$1,100.0 million thereafter.

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. Due to the impacts from COVID-19 on availability of commercial paper, the Company also utilized its revolving committed credit facilities to meet funding needs. On October 25, 2018, the Company entered into a Fourth Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of 12 banks. This Credit Agreement provides a \$750.0 million multi-year unsecured committed revolving credit facility through October 25, 2023. On May 4, 2020, the Company entered into a 364-Day Credit Agreement with a syndicate of 10 banks, all of which are also lenders under the Credit Agreement. The 364-Day Credit Agreement provides an additional \$200.0 million unsecured committed revolving credit facility. 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. At September 30, 2020, the commercial paper program is backed by the Credit Agreement.

At September 30, 2020, the Company had outstanding short-term notes payable to banks of \$15.0 million, all of which was issued under the Credit Agreement. The Company had outstanding commercial paper of \$15.0 million at September 30, 2020. At September 30, 2020, the weighted average interest rate on the short-term notes payable to banks was 1.51% and the weighted average interest rate on the commercial paper was 0.25%. At September 30, 2019, the Company had outstanding commercial paper of \$55.2 million with a weighted average interest rate on the commercial paper of 2.50%. The Company did not have any outstanding short-term notes payable to banks at September 30, 2019.

Debt Restrictions

The Credit Agreement 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 Company's 364-Day Credit Agreement. Since July 1, 2018, the Company recorded after-tax ceiling test impairments totaling \$326.3 million. As a result, at September 30, 2020, \$163.1 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 .55. The constraints specified in both the Credit Agreement and 364-Day Credit Agreement would have permitted an additional \$1.30 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

On March 27, 2020, the Company was downgraded by S&P to a rating of BBB- with a negative outlook. S&P subsequently improved the Company's outlook to stable during the quarter ended June 30, 2020. Combined with current ratings from other credit rating agencies, the downgrade increased the Company's short-term borrowing costs under its Credit Agreement. A further downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 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 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.

The Company's present liquidity position is believed to be adequate to satisfy known demands. Under the Company's existing indenture covenants at September 30, 2020, the Company is precluded from issuing incremental long-term unsecured indebtedness beginning in January 2021 as a result of impairments of its oil and gas properties recognized during the year ended September 30, 2020. The Company expects this restriction to extend for several quarters in fiscal 2021. Depending on the magnitude of any future impairments, it is possible that the Company's indenture covenants could restrict the Company's ability to issue additional long-term unsecured indebtedness beyond that period. The covenants would not preclude the Company from issuing long-term debt to replace maturing long-term debt, including the Company's 4.90% notes, in the principal amount of \$500 million, maturing in December 2021. Please refer to Part II, Item 7, 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 September 30, 2020) 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.

Note I — 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 September 30, 2020 and 2019. 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	At Fair Value as of September 30, 2020				
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
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	<u>\$ 124,795</u>	<u>\$ 36,677</u>	<u>\$ —</u>	<u>\$ (27,458)</u>	<u>\$ 134,014</u>
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	<u>\$ —</u>	<u>\$ 71,427</u>	<u>\$ —</u>	<u>\$ (27,458)</u>	<u>\$ 43,969</u>
Total Net Assets/(Liabilities)	<u>\$ 124,795</u>	<u>\$ (34,750)</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 90,045</u>
	At Fair Value as of September 30, 2019				
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds . . .	\$ 10,521	\$ —	\$ —	\$ —	\$ 10,521
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	2,055	—	—	(2,055)	—
Over the Counter Swaps — Gas and Oil	—	52,076	—	(1,483)	50,593
Foreign Currency Contracts	—	5	—	(2,052)	(2,047)
Other Investments:					
Balanced Equity Mutual Fund	40,660	—	—	—	40,660
Fixed Income Mutual Fund	62,339	—	—	—	62,339
Common Stock — Financial Services Industry	844	—	—	—	844
Hedging Collateral Deposits	6,832	—	—	—	6,832
Total	<u>\$ 123,251</u>	<u>\$ 52,081</u>	<u>\$ —</u>	<u>\$ (5,590)</u>	<u>\$ 169,742</u>
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	\$ 7,149	\$ —	\$ —	\$ (2,055)	\$ 5,094
Over the Counter Swaps — Gas and Oil	—	1,671	—	(1,483)	188
Foreign Currency Contracts	—	2,344	—	(2,052)	292
Total	<u>\$ 7,149</u>	<u>\$ 4,015</u>	<u>\$ —</u>	<u>\$ (5,590)</u>	<u>\$ 5,574</u>
Total Net Assets/(Liabilities)	<u>\$ 116,102</u>	<u>\$ 48,066</u>	<u>\$ —</u>	<u>\$ —</u>	<u>\$ 164,168</u>

- (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.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Derivative Financial Instruments

At September 30, 2020, the derivative financial instruments reported in Level 2 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.

At September 30, 2019, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX and ICE futures contracts used by NFR (included in the All Other category). Hedging collateral deposits of \$6.8 million at September 30, 2019, which are associated with these futures contracts, have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at September 30, 2019 consist of natural gas price swap agreements used in the Company's Exploration and Production segment and in its NFR operations, crude oil price swap agreements used in the Company's Exploration and Production segment, basis hedge swap agreements used by NFR and foreign currency contracts used in the Company's Exploration and Production segment.

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 at September 30, 2020 and September 30, 2019 are determined using the market approach based on observable market transactions of forward Canadian currency rates.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2020, 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 years ended September 30, 2020 and 2019, there were no assets or liabilities measured at fair value and classified as Level 3. For the years ended September 30, 2020 and September 30, 2019, no transfers in or out of Level 1 or Level 2 occurred.

Note J — 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:

	At September 30			
	2020 Carrying Amount	2020 Fair Value	2019 Carrying Amount	2019 Fair Value
	(Thousands)			
Long-Term Debt	\$ 2,629,576	\$ 2,778,556	\$ 2,133,718	\$ 2,257,085

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

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 September 30	
	2020	2019
	(Thousands)	
Life Insurance Contracts	\$ 41,992	\$ 41,074
Equity Mutual Fund	39,618	40,660
Fixed Income Mutual Fund	72,253	62,339
Marketable Equity Securities	639	844
	<u>\$ 154,502</u>	<u>\$ 144,917</u>

Investments in life insurance contracts are stated at their cash surrender values or net present value. Investments in an equity mutual fund, a fixed income mutual fund and the stock of an insurance company (marketable equity securities) are stated at fair value based on quoted market prices with changes in fair value recognized in net income. The insurance contracts and marketable equity and fixed income securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment. 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 September 30, 2020 and September 30, 2019. 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. Prior to October 1, 2019, gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness were recognized in current earnings rather than as a component of other comprehensive income (loss). For the year ended September 30, 2019, the Company recorded \$2.1 million of hedging ineffectiveness gains that impacted operating revenue. With the October 1, 2019 adoption of the authoritative guidance that changes the financial reporting of hedging relationships and simplifies the application of hedge accounting, derivative instruments that are designated and qualify as a cash flow hedge will no longer have hedge ineffectiveness or a component excluded from the assessment of the effectiveness.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

As of September 30, 2020, the Company had the following commodity derivative contracts (swaps and no cost collars) outstanding:

<u>Commodity</u>	<u>Units</u>
Natural Gas	286.7 Bcf
Crude Oil	1,548,000 Bbls

As of September 30, 2020, the Company was hedging a total of \$78.0 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts.

As of September 30, 2020, the Company had \$34.8 million (\$24.9 million after tax) of net hedging losses included in the accumulated other comprehensive income (loss) balance. It is expected that \$26.7 million (\$19.1 million after tax) of such 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
Year Ended September 30, 2020 and 2019 (Dollar Amounts in Thousands)**

<u>Derivatives in Cash Flow Hedging Relationships</u>	<u>Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) for the Year Ended September 30,</u>		<u>Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income</u>	<u>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 Year Ended September 30,</u>	
	<u>2020</u>	<u>2019</u>		<u>2020</u>	<u>2019</u>
Commodity Contracts	\$ 9,905	\$ 82,984	Operating Revenue	\$ 93,691	\$ (3,460)
Commodity Contracts	391	(1,037)	Purchased Gas	661	(1,182)
Foreign Currency Contracts	(434)	(2,646)	Operating Revenue	(1,057)	(822)
Total	<u>\$ 9,862</u>	<u>\$ 79,301</u>		<u>\$ 93,295</u>	<u>\$ (5,464)</u>

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 eight are in a net gain position. On average, the Company had \$1.2 million of credit exposure per counterparty in a gain position at September 30, 2020. The maximum credit exposure per counterparty in a gain position at September 30, 2020 was \$3.9 million. As of September 2020, 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 September 30, 2020, fifteen of the seventeen counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps and applicable foreign currency forward contracts) had a common credit-risk related contingency feature. In the event the Company's credit rating

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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 September 30, 2020, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was \$8.6 million according to the Company's internal model (discussed in Note I — Fair Value Measurements). At September 30, 2020, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was \$44.0 million according to the Company's internal model. For its over-the-counter swap agreements and foreign currency forward contracts, no hedging collateral deposits were required to be posted by the Company at September 30, 2020.

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 K — Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan). The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Certain non-collectively bargained employees hired after June 30, 2003 and certain collectively bargained employees hired after October 31, 2003 are eligible for a Retirement Savings Account benefit provided under the Company's defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account were \$4.2 million, \$3.9 million and \$3.5 million for the years ended September 30, 2020, 2019 and 2018, respectively. Costs associated with the Company's contributions to the Tax-Deferred Savings Plans, exclusive of the costs associated with the Retirement Savings Account, were \$6.7 million, \$6.4 million, and \$6.2 million for the years ended September 30, 2020, 2019 and 2018, respectively.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The other post-retirement benefits cover certain non-collectively bargained employees hired before January 1, 2003 and certain collectively bargained employees hired before October 31, 2003.

The Company's policy is to fund the Retirement Plan with at least an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. The Company has established VEBA trusts for its other post-retirement benefits. Contributions to the VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code and regulations and are made to fund employees' other post-retirement benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its other post-retirement benefits. They are separate accounts within the Retirement Plan trust used to pay retiree medical benefits for the associated participants in the Retirement Plan. Although these accounts are in the Retirement Plan trust, for funding status purposes as shown below, the 401(h) accounts are included in Fair Value of Assets under Other Post-Retirement Benefits. Contributions are tax-deductible when made, subject to limitations contained in the Internal Revenue Code and regulations.

The expected return on Retirement Plan assets, a component of net periodic benefit cost shown in the tables below, is applied to the market-related value of plan assets. The market-related value of plan assets is the market value as of the measurement date adjusted for variances between actual returns and expected returns (from previous years) that have not been reflected in net periodic benefit costs. The expected return on other post-retirement benefit assets (i.e. the VEBA trusts and 401(h) accounts), which is a component of net periodic benefit cost shown in the tables below, is applied to the fair value of assets as of the measurement date.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and other post-retirement benefits are shown in the tables below. The components of net periodic benefit cost other than service cost are presented in Other Income (Deductions) on the Consolidated Statements of Income. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is September 30 for fiscal years 2020, 2019 and 2018.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2020	2019	2018	2020	2019	2018
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	\$ 1,097,625	\$ 985,690	\$ 1,054,826	\$ 468,163	\$ 435,986	\$ 462,619
Service Cost	9,318	8,482	9,921	1,609	1,519	1,830
Interest Cost	29,930	38,378	33,006	12,913	17,145	14,801
Plan Participants' Contributions	—	—	—	3,058	2,930	2,894
Retiree Drug Subsidy Receipts	—	—	—	1,411	1,855	1,545
Actuarial (Gain) Loss	65,908	127,748	(50,218)	16,396	34,401	(21,039)
Benefits Paid	(63,676)	(62,673)	(61,845)	(26,828)	(25,673)	(26,664)
Benefit Obligation at End of Period	\$ 1,139,105	\$ 1,097,625	\$ 985,690	\$ 476,722	\$ 468,163	\$ 435,986
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	\$ 968,449	\$ 924,506	\$ 910,719	\$ 524,127	\$ 513,800	\$ 514,017
Actual Return on Plan Assets	87,402	77,401	42,652	44,448	30,006	20,657
Employer Contributions	24,621	29,215	32,980	3,080	3,064	2,896
Plan Participants' Contributions	—	—	—	3,058	2,930	2,894
Benefits Paid	(63,676)	(62,673)	(61,845)	(26,828)	(25,673)	(26,664)
Fair Value of Assets at End of Period	\$ 1,016,796	\$ 968,449	\$ 924,506	\$ 547,885	\$ 524,127	\$ 513,800
Net Amount Recognized at End of Period (Funded Status)	\$ (122,309)	\$ (129,176)	\$ (61,184)	\$ 71,163	\$ 55,964	\$ 77,814
Amounts Recognized in the Balance Sheets Consist of:						
Non-Current Liabilities	\$ (122,309)	\$ (129,176)	\$ (61,184)	\$ (4,872)	\$ (4,553)	\$ (4,919)
Non-Current Assets	—	—	—	76,035	60,517	82,733
Net Amount Recognized at End of Period	\$ (122,309)	\$ (129,176)	\$ (61,184)	\$ 71,163	\$ 55,964	\$ 77,814
Accumulated Benefit Obligation	\$ 1,096,427	\$ 1,053,914	\$ 946,763	N/A	N/A	N/A
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	2.66 %	3.15 %	4.30 %	2.71 %	3.17 %	4.31 %
Rate of Compensation Increase	4.70 %	4.70 %	4.70 %	4.70 %	4.70 %	4.70 %

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2020	2019	2018	2020	2019	2018
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	\$ 9,318	\$ 8,482	\$ 9,921	\$ 1,609	\$ 1,519	\$ 1,830
Interest Cost	29,930	38,378	33,006	12,913	17,145	14,801
Expected Return on Plan Assets ...	(60,063)	(62,368)	(61,715)	(29,232)	(30,157)	(31,482)
Amortization of Prior Service Cost (Credit)	729	826	938	(429)	(429)	(429)
Recognition of Actuarial Loss(1) ..	39,384	32,096	37,205	535	5,962	10,558
Net Amortization and Deferral for Regulatory Purposes	5,359	2,493	9,027	25,596	16,481	15,028
Net Periodic Benefit Cost	<u>\$ 24,657</u>	<u>\$ 19,907</u>	<u>\$ 28,382</u>	<u>\$ 10,992</u>	<u>\$ 10,521</u>	<u>\$ 10,306</u>
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Effective Discount Rate for Benefit Obligations	3.15 %	4.30 %	3.77 %	3.17 %	4.31 %	3.81 %
Effective Rate for Interest on Benefit Obligations	2.81 %	4.03 %	3.23 %	2.84 %	4.05 %	3.29 %
Effective Discount Rate for Service Cost	3.31 %	4.40 %	4.00 %	3.39 %	4.43 %	4.10 %
Effective Rate for Interest on Service Cost	3.12 %	4.29 %	3.73 %	3.30 %	4.39 %	3.98 %
Expected Return on Plan Assets ...	6.40 %	6.75 %	7.00 %	5.70 %	6.00 %	6.25 %
Rate of Compensation Increase ...	4.70 %	4.70 %	4.70 %	4.70 %	4.70 %	4.70 %

- (1) Distribution Corporation's New York jurisdiction calculates the amortization of the actuarial loss on a vintage year basis over 10 years, as mandated by the NYPSC. All the other subsidiaries of the Company utilize the corridor approach.

The Net Periodic Benefit Cost in the table above includes the effects of regulation. The Company recovers pension and other post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorizations. Certain of those commission authorizations established tracking mechanisms which allow the Company to record the difference between the amount of pension and other post-retirement benefit costs recoverable in rates and the amounts of such costs as determined under the existing authoritative guidance as either a regulatory asset or liability, as appropriate. Any activity under the tracking mechanisms (including the amortization of pension and other post-retirement regulatory assets and liabilities) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

In addition to the Retirement Plan discussed above, the Company also has Non-Qualified benefit plans that cover a group of management employees designated by the Chief Executive Officer of the Company. These plans provide for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit costs associated with these plans were \$8.9 million, \$7.6 million and \$6.8 million in 2020, 2019 and 2018, respectively. The components of net periodic benefit cost other than service costs associated with these plans are presented in Other Income (Deductions) on

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

the Consolidated Statements of Income. The accumulated benefit obligations for the plans were \$78.7 million, \$79.8 million and \$70.6 million at September 30, 2020, 2019 and 2018, respectively. The projected benefit obligations for the plans were \$98.1 million, \$99.5 million and \$86.1 million at September 30, 2020, 2019 and 2018, respectively. At September 30, 2020, \$14.5 million of the projected benefit obligation is recorded in Other Accruals and Current Liabilities and the remaining \$83.6 million is recorded in Other Deferred Credits on the Consolidated Balance Sheets. At September 30, 2019, \$13.2 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining \$86.3 million was recorded in Other Deferred Credits on the Consolidated Balance Sheets. At September 30, 2018, \$11.5 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining \$74.6 million was recorded in Other Deferred Credits on the Consolidated Balance Sheets. The weighted average discount rates for these plans were 1.92%, 2.77% and 4.02% as of September 30, 2020, 2019 and 2018, respectively and the weighted average rates of compensation increase for these plans were 8.00%, 8.00% and 7.75% as of September 30, 2020, 2019 and 2018, respectively.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2020, the changes in such amounts during 2020, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2021 are presented in the table below:

	<u>Retirement Plan</u>	<u>Other Post-Retirement Benefits</u>	<u>Non-Qualified Benefit Plans</u>
		(Thousands)	
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Loss	\$ (215,330)	\$ (28,044)	\$ (34,065)
Prior Service (Cost) Credit	(3,641)	2,401	—
Net Amount Recognized	<u>\$ (218,971)</u>	<u>\$ (25,643)</u>	<u>\$ (34,065)</u>
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2020(1)			
Increase in Actuarial Loss, excluding amortization(2)	\$ (38,568)	\$ (1,180)	\$ (5,929)
Change due to Amortization of Actuarial Loss	39,384	535	5,341
Prior Service (Cost) Credit	729	(429)	—
Net Change	<u>\$ 1,545</u>	<u>\$ (1,074)</u>	<u>\$ (588)</u>
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Loss	\$ (36,814)	\$ (849)	\$ (5,852)
Prior Service (Cost) Credit	(631)	429	—
Net Amount Expected to be Recognized	<u>\$ (37,445)</u>	<u>\$ (420)</u>	<u>\$ (5,852)</u>

(1) Amounts presented are shown before recognizing deferred taxes.

(2) Amounts presented include the impact of actuarial gains/losses related to return on assets, as well as the Actuarial (Gain) Loss amounts presented in the Change in Benefit Obligation.

In order to adjust the funded status of its pension (tax-qualified and non-qualified) and other post-retirement benefit plans at September 30, 2020, the Company recorded a \$3.8 million decrease to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a \$3.9 million (pre-tax) decrease to Accumulated Other Comprehensive Income.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The effect of the discount rate change for the Retirement Plan in 2020 was to increase the projected benefit obligation of the Retirement Plan by \$61.3 million. The mortality improvement projection scale was updated, which decreased the projected benefit obligation of the Retirement Plan in 2020 by \$3.3 million. Other actuarial experience increased the projected benefit obligation for the Retirement Plan in 2020 by \$7.9 million. The effect of the discount rate change for the Retirement Plan in 2019 was to increase the projected benefit obligation of the Retirement Plan by \$128.4 million. The effect of the discount rate change for the Retirement Plan in 2018 was to decrease the projected benefit obligation of the Retirement Plan by \$58.1 million.

The Company made cash contributions totaling \$24.6 million to the Retirement Plan during the year ended September 30, 2020. The Company expects that the annual contribution to the Retirement Plan in 2021 will be in the range of \$15.0 million to \$25.0 million.

The following Retirement Plan benefit payments, which reflect expected future service, are expected to be paid by the Retirement Plan during the next five years and the five years thereafter: \$66.8 million in 2021; \$67.2 million in 2022; \$67.4 million in 2023; \$67.4 million in 2024; \$67.1 million in 2025; and \$326.8 million in the five years thereafter.

The effect of the discount rate change in 2020 was to increase the other post-retirement benefit obligation by \$25.4 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2020 by \$2.5 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2020 by \$6.5 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The effect of the discount rate change in 2019 was to increase the other post-retirement benefit obligation by \$57.2 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2019 by \$3.9 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2019 by \$18.9 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The effect of the discount rate change in 2018 was to decrease the other post-retirement benefit obligation by \$25.8 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2018 by \$2.4 million. Other actuarial experience increased the other post-retirement benefit obligation in 2018 by \$7.3 million primarily attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and drug subsidy assumptions based on actual experience.

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 provides for a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

The estimated gross other post-retirement benefit payments and gross amount of Medicare Part D prescription drug subsidy receipts are as follows (dollars in thousands):

	<u>Benefit Payments</u>	<u>Subsidy Receipts</u>
2021	\$ 28,361	\$ (1,950)
2022	\$ 28,820	\$ (2,064)
2023	\$ 29,085	\$ (2,172)
2024	\$ 29,192	\$ (2,273)
2025	\$ 29,231	\$ (2,356)
2026 through 2030	\$ 143,696	\$ (12,763)

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Assumed health care cost trend rates as of September 30 were:

	<u>2020</u>	<u>2019</u>	<u>2018</u>
Rate of Medical Cost Increase for Pre Age 65 Participants	5.42 % (1)	5.50 % (1)	5.59 % (1)
Rate of Medical Cost Increase for Post Age 65 Participants	4.75 % (1)	4.75 % (1)	4.75 % (1)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	6.80 % (1)	7.35 % (1)	7.89 % (1)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	4.75 % (1)	4.75 % (1)	4.75 % (1)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy . . .	6.20 % (1)	6.84 % (1)	7.18 % (1)

(1) It was assumed that this rate would gradually decline to 4.5% by 2039.

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2020 would increase by \$61.7 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2020 by \$2.5 million. If the health care cost trend rates were decreased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2020 would decrease by \$51.5 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2020 by \$1.8 million.

The Company made cash contributions totaling \$2.8 million to its VEBA trusts during the year ended September 30, 2020. In addition, the Company made direct payments of \$0.3 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2020. The Company expects that the annual contribution to its VEBA trusts in 2021 will be in the range of \$2.5 million to \$3.0 million.

Investment Valuation

The Retirement Plan assets and other post-retirement benefit assets are valued under the current fair value framework. See Note I — Fair Value Measurements for further discussion regarding the definition and levels of fair value hierarchy established by the authoritative guidance.

The inputs or methodologies used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of September 30, 2020 and 2019, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall, based on the lowest level input that is significant to the fair value measurement in its entirety (dollars in thousands):

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

At September 30, 2020					
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(7)
Retirement Plan Investments					
Domestic Equities(1)	\$ 188,939	\$ 118,124	\$ —	\$ —	\$ 70,815
International Equities(2)	94,603	—	—	—	94,603
Global Equities(3)	77,736	—	—	—	77,736
Domestic Fixed Income(4)	512,693	2,000	457,381	—	53,312
International Fixed Income(5)	20,201	—	20,201	—	—
Global Fixed Income(6)	79,595	—	—	—	79,595
Real Estate	106,167	—	—	471	105,696
Cash Held in Collective Trust Funds	18,023	—	—	—	18,023
Total Retirement Plan Investments	1,097,957	120,124	477,582	471	499,780
401(h) Investments	(80,511)	(8,809)	(35,021)	(35)	(36,646)
Total Retirement Plan Investments (excluding 401(h) Investments)	\$ 1,017,446	\$ 111,315	\$ 442,561	\$ 436	\$ 463,134
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(650)				
Total Retirement Plan Assets	<u>\$ 1,016,796</u>				

At September 30, 2019					
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(7)
Retirement Plan Investments					
Domestic Equities(1)	\$ 175,812	\$ 114,324	\$ —	\$ —	\$ 61,488
International Equities(2)	81,631	—	—	—	81,631
Global Equities(3)	70,095	—	—	—	70,095
Domestic Fixed Income(4)	493,839	1,784	439,255	—	52,800
International Fixed Income(5)	17,744	—	17,744	—	—
Global Fixed Income(6)	75,329	—	—	—	75,329
Real Estate	107,764	—	—	3,154	104,610
Cash Held in Collective Trust Funds	18,310	—	—	—	18,310
Total Retirement Plan Investments	1,040,524	116,108	456,999	3,154	464,263
401(h) Investments	(73,688)	(8,205)	(32,295)	(223)	(32,965)
Total Retirement Plan Investments (excluding 401(h) Investments)	\$ 966,836	\$ 107,903	\$ 424,704	\$ 2,931	\$ 431,298
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	1,613				
Total Retirement Plan Assets	<u>\$ 968,449</u>				

- (1) Domestic Equities include mostly collective trust funds, common stock, and exchange traded funds.
- (2) International Equities are comprised of collective trust funds.
- (3) Global Equities are comprised of collective trust funds.
- (4) Domestic Fixed Income securities include mostly collective trust funds, corporate/government bonds and mortgages, and exchange traded funds.
- (5) International Fixed Income securities are comprised mostly of corporate/government bonds.
- (6) Global Fixed Income securities are comprised of a collective trust fund.
- (7) Reflects the authoritative guidance related to investments measured at net asset value (NAV).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

At September 30, 2020					
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(1)
Other Post-Retirement Benefit Assets held in VEBA Trusts					
Collective Trust Funds — Global Equities	\$ 153,923	\$ —	\$ —	\$ —	\$153,923
Exchange Traded Funds — Fixed Income	301,290	301,290	—	—	—
Cash Held in Collective Trust Funds	13,841	—	—	—	13,841
Total VEBA Trust Investments	469,054	301,290	—	—	167,764
401(h) Investments	80,511	8,809	35,021	35	36,646
Total Investments (including 401(h) Investments)	\$ 549,565	\$ 310,099	\$ 35,021	\$ 35	\$204,410
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(1,680)				
Total Other Post-Retirement Benefit Assets	\$ 547,885				
At September 30, 2019					
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(1)
Other Post-Retirement Benefit Assets held in VEBA Trusts					
Collective Trust Funds — Global Equities	\$ 167,966	\$ —	\$ —	\$ —	\$167,966
Exchange Traded Funds — Fixed Income	275,296	275,296	—	—	—
Cash Held in Collective Trust Funds	8,229	—	—	—	8,229
Total VEBA Trust Investments	451,491	275,296	—	—	176,195
401(h) Investments	73,688	8,205	32,295	223	32,965
Total Investments (including 401(h) Investments)	\$ 525,179	\$ 283,501	\$ 32,295	\$ 223	\$209,160
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(1,052)				
Total Other Post-Retirement Benefit Assets	\$ 524,127				

(1) Reflects the authoritative guidance related to investments measured at net asset value (NAV).

The fair values disclosed in the above tables may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

The following tables provide a reconciliation of the beginning and ending balances of the Retirement Plan and other post-retirement benefit assets measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3). For the years ended September 30, 2020 and September 30, 2019, there were no transfers from Level 1 to Level 2. In addition, as shown in the following tables, there were no transfers in or out of Level 3.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Retirement Plan Level 3 Assets (Thousands)		
	Real Estate	Excluding 401(h) Investments	Total
Balance at September 30, 2018	\$ 3,194	\$ (218)	\$ 2,976
Unrealized Gains/(Losses)	(37)	(5)	(42)
Sales	(3)	—	(3)
Balance at September 30, 2019	3,154	(223)	2,931
Unrealized Gains/(Losses)	(2,683)	188	(2,495)
Sales	—	—	—
Balance at September 30, 2020	<u>\$ 471</u>	<u>\$ (35)</u>	<u>\$ 436</u>

	Other Post-Retirement Benefit Level 3 Assets (Thousands)	
	401(h) Investments	
Balance at September 30, 2018	\$	218
Unrealized Gains/(Losses)		5
Sales		—
Balance at September 30, 2019		223
Unrealized Gains/(Losses)		(188)
Sales		—
Balance at September 30, 2020	<u>\$</u>	<u>35</u>

The Company's assumption regarding the expected long-term rate of return on plan assets is 6.00% (Retirement Plan) and 5.40% (other post-retirement benefits), effective for fiscal 2021. The return assumption reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes projected capital market conditions and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

The long-term investment objective of the Retirement Plan trust, the VEBA trusts and the 401(h) accounts is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). The target allocation for the Retirement Plan and the VEBA trusts (including 401(h) accounts) is 30-50% equity securities, 50-70% fixed income securities (including return-seeking investments) and 0-15% other (including return-seeking investments). Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trusts, VEBA trusts and the 401(h) accounts have no significant concentrations of risk in any one country (other than the United States), industry or entity.

Investment managers are retained to manage separate pools of assets. Comparative market and peer group performance of individual managers and the total fund are monitored on a regular basis, and reviewed by the Company's Retirement Committee on at least a quarterly basis.

The Company determines the service and interest cost components of net periodic benefit cost using the spot rate approach, which uses individual spot rates along the yield curve that correspond to the timing of each benefit payment in order to determine the discount rate. The individual spot rates along the yield curve are determined by an above mean methodology in that the coupon interest rates that are in the lower 50th percentile

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

are excluded based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities.

Note L — 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 September 30, 2020, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately \$6.4 million, which includes a \$3.4 million estimated minimum liability to remediate a former manufactured gas plant site located in New York. In March 2018, the NYDEC issued a Record of Decision for this New York site and the minimum liability reflects the remedy selected in the Record of Decision. The Company's liability for such clean-up costs has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at September 30, 2020. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 2 years and the Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could have an adverse financial impact on the Company.

Northern Access 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 have been appealed and are pending in a separate action before the Second Circuit Court of Appeals. 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, in its Utility segment and Exploration and Production segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: \$181.9 million in 2021, \$111.3 million in 2022, \$120.9 million in 2023, \$129.3 million in 2024, \$146.3 million in 2025 and \$1,128.2 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company, in its Pipeline and Storage segment, Gathering segment and Utility segment, has entered into several contractual commitments associated with various pipeline, compressor and gathering system modernization and expansion projects. As of September 30, 2020, the future contractual commitments related to the system modernization and expansion projects are \$98.3 million in 2021, \$6.4 million in 2022, \$3.4 million in 2023, \$3.3 million in 2024, \$3.3 million in 2025 and \$10.3 million thereafter.

The Company, in its Exploration and Production segment, has entered into contractual obligations to support its development activities and operations in Pennsylvania and California, including hydraulic fracturing and other well completion services, well tending services, well workover activities, tubing and casing, production equipment, contracts for drilling rig services and fuel purchases for steam generation. The future contractual commitments are \$109.3 million in 2021, \$15.2 million in 2022 and \$0.7 million in 2023. There are no contractual commitments extending beyond 2023.

The Company is involved in other litigation arising in the normal course of business. In addition to the regulatory matters discussed in Note F — Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business. These other litigation and regulatory 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 M — 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 Exploration and Production segment, through Seneca, is engaged in exploration for and development of natural gas and oil reserves in the Appalachian region of the United States and in California.

The Pipeline and Storage segment operations are regulated by the FERC for both Supply Corporation and Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers, exploration and production companies (including Seneca) and pipeline companies in the northeastern United States markets. Empire transports and stores natural gas for major industrial companies, utilities (including Distribution Corporation) and power producers in New York State. Empire also transports natural gas for natural gas marketers and exploration and production companies (including Seneca) from natural gas producing areas in Pennsylvania to markets in New York and to interstate pipeline delivery points with access to additional markets in the northeastern United States and Canada.

The Gathering segment is comprised of Midstream Company's operations. Midstream Company builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region and currently provides gathering services to Seneca.

The Utility segment operations are regulated by the NYPSC and the PaPUC and are carried out by Distribution Corporation. Distribution Corporation sells natural gas to retail customers and provides natural gas transportation services in western New York and northwestern Pennsylvania.

The data presented in the tables below reflects financial information for the segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A —

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. 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.

Year Ended September 30, 2020								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	\$ 607,453	\$ 205,998	\$ 72	\$ 642,855	\$ 1,456,378	\$ 89,435	\$ 478	\$ 1,546,291
Intersegment Revenues	\$ —	\$ 103,606	\$ 142,821	\$ 9,443	\$ 255,870	\$ 836	\$ (256,706)	\$ —
Interest Income	\$ 698	\$ 1,475	\$ 545	\$ 2,262	\$ 4,980	\$ 860	\$ (833)	\$ 5,007
Interest Expense	\$ 58,098	\$ 32,731	\$ 10,877	\$ 22,150	\$ 123,856	\$ 66	\$ (6,845)	\$ 117,077
Depreciation, Depletion and Amortization	\$ 172,124	\$ 53,951	\$ 22,440	\$ 55,248	\$ 303,763	\$ 1,716	\$ 679	\$ 306,158
Income Tax Expense (Benefit)	\$ (41,472)	\$ 28,613	\$ 18,191	\$ 13,274	\$ 18,606	\$ 210	\$ (77)	\$ 18,739
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	\$ 449,438	\$ —	\$ —	\$ —	\$ 449,438	\$ —	\$ —	\$ 449,438
Segment Profit: Net Income (Loss)	\$ (326,904)	\$ 78,860	\$ 68,631	\$ 57,366	\$ (122,047)	\$ (269)	\$ (1,456)	\$ (123,772)
Expenditures for Additions to Long-Lived Assets	\$ 670,455	\$ 166,652	\$ 297,806	\$ 94,273	\$ 1,229,186	\$ 39	\$ (608)	\$ 1,228,617
	At September 30, 2020							
	(Thousands)							
Segment Assets	\$ 1,979,028	\$ 2,204,971	\$ 945,199	\$ 2,067,852	\$ 7,197,050	\$ 113,571	\$ (345,686)	\$ 6,964,935
Year Ended September 30, 2019								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Elimination	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	\$ 632,740	\$ 195,808	\$ 11	\$ 715,813	\$ 1,544,372	\$ 148,582	\$ 378	\$ 1,693,332
Intersegment Revenues	\$ —	\$ 92,475	\$ 127,064	\$ 11,629	\$ 231,168	\$ 1,127	\$ (232,295)	\$ —
Interest Income	\$ 1,107	\$ 2,982	\$ 546	\$ 1,809	\$ 6,444	\$ 1,291	\$ (1,670)	\$ 6,065
Interest Expense	\$ 54,777	\$ 29,142	\$ 9,406	\$ 23,443	\$ 116,768	\$ 21	\$ (10,033)	\$ 106,756
Depreciation, Depletion and Amortization	\$ 154,784	\$ 44,947	\$ 20,038	\$ 53,832	\$ 273,601	\$ 1,291	\$ 768	\$ 275,660
Income Tax Expense (Benefit)	\$ 32,978	\$ 23,238	\$ 20,895	\$ 13,967	\$ 91,078	\$ (955)	\$ (4,902)	\$ 85,221
Segment Profit: Net Income (Loss)	\$ 111,807	\$ 74,011	\$ 58,413	\$ 60,871	\$ 305,102	\$ (1,811)	\$ 999	\$ 304,290
Expenditures for Additions to Long-Lived Assets	\$ 491,889	\$ 143,005	\$ 49,650	\$ 95,847	\$ 780,391	\$ 128	\$ 727	\$ 781,246
	At September 30, 2019							
	(Thousands)							
Segment Assets	\$ 1,972,776	\$ 1,893,514	\$ 547,995	\$ 1,991,338	\$ 6,405,623	\$ 122,241	\$ (65,707)	\$ 6,462,157

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Year Ended September 30, 2018								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	\$ 564,547	\$ 210,345	\$ 41	\$ 674,726	\$ 1,449,659	\$ 142,349	\$ 660	\$ 1,592,668
Intersegment Revenues	\$ —	\$ 89,981	\$ 107,856	\$ 12,800	\$ 210,637	\$ 826	\$ (211,463)	\$ —
Interest Income	\$ 1,479	\$ 2,748	\$ 1,106	\$ 1,591	\$ 6,924	\$ 1,073	\$ (1,231)	\$ 6,766
Interest Expense	\$ 54,288	\$ 31,383	\$ 9,560	\$ 26,753	\$ 121,984	\$ 22	\$ (7,484)	\$ 114,522
Depreciation, Depletion and Amortization	\$ 124,274	\$ 43,463	\$ 17,313	\$ 53,253	\$ 238,303	\$ 1,902	\$ 756	\$ 240,961
Income Tax Expense (Benefit) ..	\$ (41,962)	\$ 17,806	\$ (17,677)	\$ 15,258	\$ (26,575)	\$ 2,125	\$ 16,956	\$ (7,494)
Segment Profit: Net Income (Loss)	\$ 180,632	\$ 97,246	\$ 83,519	\$ 51,217	\$ 412,614	\$ 261	\$ (21,354)	\$ 391,521
Expenditures for Additions to Long-Lived Assets	\$ 380,677	\$ 92,832	\$ 61,728	\$ 85,648	\$ 620,885	\$ 41	\$ (20,324)	\$ 600,602
	At September 30, 2018							
	(Thousands)							
Segment Assets	\$ 1,568,563	\$ 1,848,180	\$ 533,608	\$ 1,921,971	\$ 5,872,322	\$ 129,080	\$ 35,084	\$ 6,036,486

(1) All Revenue from External Customers originated in the United States.

Geographic Information

				At September 30		
				2020	2019	2018
				(Thousands)		

Long-Lived Assets:

United States	\$ 6,597,313	\$ 6,099,534	\$ 5,491,895
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Note N — Quarterly Financial Data (unaudited)

In the opinion of management, the following quarterly information includes all adjustments necessary for a fair statement of the results of operations for such periods. Per common share amounts are calculated using the weighted average number of shares outstanding during each quarter. The total of all quarters may differ from the per common share amounts shown on the Consolidated Statements of Income. Those per common share amounts are based on the weighted average number of shares outstanding for the entire fiscal year. Because of the seasonal nature of the Company's heating business, there are substantial variations in operations reported on a quarterly basis.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

<u>Quarter Ended</u>	<u>Operating Revenues</u>	<u>Operating Income (Loss)</u>	<u>Net Income (Loss) Available for Common Stock</u>	<u>Earnings (Loss) per Common Share</u>		
				<u>Basic</u>	<u>Diluted</u>	
(Thousands, except per common share amounts)						
<u>2020</u>						
9/30/2020	\$ 287,989	\$ (173,979)	\$ (145,545) (1)	\$ (1.60)	\$ (1.60)	
6/30/2020	\$ 323,019	\$ 80,397	\$ 41,250 (2)	\$ 0.47	\$ 0.47	
3/31/2020	\$ 491,095	\$ (24,580)	\$ (106,068) (3)	\$ (1.23)	\$ (1.23)	
12/31/2019	\$ 444,188	\$ 148,020	\$ 86,591	\$ 1.00	\$ 1.00	
<u>2019</u>						
9/30/2019	\$ 293,341	\$ 83,940	\$ 47,282	\$ 0.55	\$ 0.54	
6/30/2019	\$ 357,200	\$ 112,827	\$ 63,753	\$ 0.74	\$ 0.73	
3/31/2019	\$ 552,544	\$ 153,359	\$ 90,595	\$ 1.05	\$ 1.04	
12/31/2018	\$ 490,247	\$ 161,683	\$ 102,660 (4)	\$ 1.19	\$ 1.18	

- (1) Includes a non-cash \$253.4 million impairment charge (\$183.7 million after tax) associated with the Exploration and Production segment's oil and gas producing properties.
- (2) Includes a non-cash \$18.2 million impairment charge (\$13.3 million after tax) associated with the Exploration and Production segment's oil and gas producing properties.
- (3) Includes a non-cash \$177.8 million impairment charge (\$129.3 million after tax) associated with the Exploration and Production segment's oil and gas producing properties and a \$56.8 million valuation allowance recorded against certain deferred tax assets.
- (4) Includes a \$5.0 million reduction to income tax expense associated with the remeasurement of accumulated deferred income taxes in accordance with the 2017 Tax Reform Act.

Note O — Supplementary Information for Oil and Gas Producing Activities (unaudited, except for Capitalized Costs Relating to Oil and Gas Producing Activities)

The Company follows authoritative guidance related to oil and gas exploration and production activities that aligns the reserve estimation and disclosure requirements with the requirements of the SEC Modernization of Oil and Gas Reporting rule, which the Company also follows. The SEC rules require companies to value their year-end reserves using 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 following supplementary information is presented in accordance with the authoritative guidance regarding disclosures about oil and gas producing activities and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30	
	2020	2019
	(Thousands)	
Proved Properties(1)	\$ 6,238,830	\$ 5,623,623
Unproved Properties	148,075	53,498
	6,386,905	5,677,121
Less — Accumulated Depreciation, Depletion and Amortization	4,628,765	4,012,568
	<u>\$ 1,758,140</u>	<u>\$ 1,664,553</u>

(1) Includes asset retirement costs of \$132.6 million and \$70.5 million at September 30, 2020 and 2019, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. 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. Although the timing of the ultimate evaluation or disposition of the unproved properties cannot be determined, the Company expects the majority of its acquisition costs associated with unproved properties to be transferred into the amortization base by 2025. It expects the majority of its development and exploration costs associated with unproved properties to be transferred into the amortization base by 2023. Following is a summary of costs excluded from amortization at September 30, 2020:

	Total as of September 30, 2020	Year Costs Incurred			
		2020	2019	2018	Prior
		(Thousands)			
Acquisition Costs	\$ 64,218	\$ 39,953	\$ —	\$ —	\$ 24,265
Development Costs	75,138	54,761	17,326	403	2,648
Exploration Costs	7,606	—	—	—	7,606
Capitalized Interest	1,113	969	41	—	103
	<u>\$ 148,075</u>	<u>\$ 95,683</u>	<u>\$ 17,367</u>	<u>\$ 403</u>	<u>\$ 34,622</u>

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

	Year Ended September 30		
	2020	2019	2018
	(Thousands)		
United States			
Property Acquisition Costs:			
Proved	\$ 245,976	\$ 3,136	\$ 1,544
Unproved	42,922	3,679	4,286
Exploration Costs	3,891	2,060	29,365
Development Costs(1)	355,742	468,498	332,496
Asset Retirement Costs	62,080	26,192	(10,107)
	<u>\$ 710,611</u>	<u>\$ 503,565</u>	<u>\$ 357,584</u>

(1) Amounts for 2020, 2019 and 2018 include capitalized interest of \$1.0 million, \$0.2 million and \$0.3 million, respectively.

For the years ended September 30, 2020, 2019 and 2018, the Company spent \$219.9 million, \$246.0 million and \$182.3 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2020	2019	2018
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Gas (includes transfers to operations of 1,921, 2,532 and 2,134, respectively)(1)	\$ 402,447	\$ 481,048	\$ 390,642
Oil, Condensate and Other Liquids	107,844	149,078	168,254
Total Operating Revenues(2)	510,291	630,126	558,896
Production/Lifting Costs	203,670	186,626	162,721
Franchise/Ad Valorem Taxes	15,582	17,673	14,355
Purchased Emission Allowance Expense	2,930	2,527	1,883
Accretion Expense	5,237	3,723	4,266
Depreciation, Depletion and Amortization (\$0.69, \$0.71 and \$0.67 per Mcfe of production, respectively)	166,759	149,881	119,946
Impairment of Oil and Gas Producing Properties	449,438	—	—
Income Tax Expense	(92,820)	64,652	72,723
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	<u>\$ (240,505)</u>	<u>\$ 205,044</u>	<u>\$ 183,002</u>

(1) There were no revenues from sales to affiliates for all years presented.

(2) Exclusive of hedging gains and losses. See further discussion in Note J — Financial Instruments.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Reserve Quantity Information

The Company's proved oil and gas reserve estimates are prepared by the Company's reservoir engineers who meet the qualifications of Reserve Estimator per the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007. The Company maintains comprehensive internal reserve guidelines and a continuing education program designed to keep its staff up to date with current SEC regulations and guidance.

The Company's Vice President of Reservoir Engineering is the primary technical person responsible for overseeing the Company's reserve estimation process and engaging and overseeing the third party reserve audit. His qualifications include a Bachelor of Science Degree in Petroleum Engineering and over 30 years of Petroleum Engineering experience with both major and independent oil and gas companies. He has maintained oversight of the Company's reserve estimation process since 2003. He is a member of the Society of Petroleum Evaluation Engineers and a Registered Professional Engineer in the State of Texas.

The Company maintains a system of internal controls over the reserve estimation process. Management reviews the price, heat content, lease operating cost and future investment assumptions used in the economic model to determine the reserves. The Vice President of Reservoir Engineering reviews and approves all new reserve assignments and significant reserve revisions. Access to the reserve database is restricted. Significant changes to the reserve report are reviewed by senior management on a quarterly basis. Periodically, the Company's internal audit department assesses the design of these controls and performs testing to determine the effectiveness of such controls.

All of the Company's reserve estimates are audited annually by Netherland, Sewell and Associates, Inc. (NSAI). Since 1961, NSAI has evaluated gas and oil properties and independently certified petroleum reserve quantities in the United States and internationally under the Texas Board of Professional Engineers Registration No. F-002699. The primary technical persons (employed by NSAI) that are responsible for leading the audit include a professional engineer registered with the State of Texas (consulting at NSAI since 2011 and with over 4 years of prior industry experience in petroleum engineering) and a professional geoscientist registered in the State of Texas (consulting at NSAI since 2008 and with over 11 years of prior industry experience in petroleum geosciences). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2020 and did not identify any problems which would cause it to take exception to those estimates.

The reliable technologies that were utilized in estimating the reserves include wire line open-hole log data, performance data, log cross sections, core data, 2D and 3D seismic data and statistical analysis. The statistical method utilized production performance from both the Company's and competitors' wells. Geophysical data includes data from the Company's wells, third-party wells, published documents and state data-sites, and 2D and 3D seismic data. These were used to confirm continuity of the formation.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Gas MMcf		
	U.S.		
	Appalachian Region	West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:			
September 30, 2017	1,926,614	46,506	1,973,120
Extensions and Discoveries	521,694 (1)	—	521,694
Revisions of Previous Estimates	90,113	3,322	93,435
Production	(160,499) (2)	(2,407)	(162,906)
Sale of Minerals in Place	(57,420)	(10,581)	(68,001)
September 30, 2018	2,320,502	36,840	2,357,342
Extensions and Discoveries	686,549 (1)	—	686,549
Revisions of Previous Estimates	104,741	(1,233)	103,508
Production	(195,906) (2)	(1,974)	(197,880)
September 30, 2019	2,915,886	33,633	2,949,519
Extensions and Discoveries	7,246 (1)	—	7,246
Revisions of Previous Estimates	(85,647)	(2,772)	(88,419)
Production	(225,513) (2)	(1,889)	(227,402)
Purchases of Minerals in Place	684,141	—	684,141
September 30, 2020	3,296,113	28,972	3,325,085
Proved Developed Reserves:			
September 30, 2017	1,316,596	46,506	1,363,102
September 30, 2018	1,569,692	36,840	1,606,532
September 30, 2019	1,901,162	33,633	1,934,795
September 30, 2020	2,744,851	28,972	2,773,823
Proved Undeveloped Reserves:			
September 30, 2017	610,018	—	610,018
September 30, 2018	750,810	—	750,810
September 30, 2019	1,014,724	—	1,014,724
September 30, 2020	551,262	—	551,262

- (1) Extensions and discoveries include 274 Bcf (during 2018), 175 Bcf (during 2019) and 7 Bcf (during 2020), of Marcellus Shale gas (which exceed 15% of total reserves) in the Appalachian region. Extensions and discoveries include 248 Bcf (during 2018), 512 Bcf (during 2019) and 0 Bcf (during 2020), of Utica Shale gas (which exceed 15% of total reserves) in the Appalachian region.
- (2) Production includes 150,196 MMcf (during 2018), 163,015 MMcf (during 2019) and 169,453 MMcf (during 2020), from Marcellus Shale fields. Production includes 9,409 MMcf (during 2018), 32,095 MMcf (during 2019) and 55,392 MMcf (during 2020), from Utica Shale fields.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Oil Mbbl		
	U.S.		
	Appalachian Region	West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:			
September 30, 2017	28	30,179	30,207
Extensions and Discoveries	—	2,301	2,301
Revisions of Previous Estimates	(10)	2,487	2,477
Production	(4)	(2,531)	(2,535)
Sales of Minerals in Place	—	(4,787)	(4,787)
September 30, 2018	14	27,649	27,663
Extensions and Discoveries	—	787	787
Revisions of Previous Estimates	2	(1,256)	(1,254)
Production	(3)	(2,320)	(2,323)
September 30, 2019	13	24,860	24,873
Extensions and Discoveries	—	288	288
Revisions of Previous Estimates	2	(715)	(713)
Production	(3)	(2,345)	(2,348)
September 30, 2020	12	22,088	22,100
Proved Developed Reserves:			
September 30, 2017	28	29,771	29,799
September 30, 2018	14	26,689	26,703
September 30, 2019	13	24,246	24,259
September 30, 2020	12	22,088	22,100
Proved Undeveloped Reserves:			
September 30, 2017	—	408	408
September 30, 2018	—	960	960
September 30, 2019	—	614	614
September 30, 2020	—	—	—

The Company's proved undeveloped (PUD) reserves decreased from 1,018 Bcfe at September 30, 2019 to 551 Bcfe at September 30, 2020. PUD reserves in the Marcellus Shale decreased from 383 Bcfe at September 30, 2019 to 287 Bcfe at September 30, 2020. PUD reserves in the Utica Shale decreased from 632 Bcfe at September 30, 2019 to 265 Bcfe at September 30, 2020. The Company's total PUD reserves were 16% of total proved reserves at September 30, 2020, down from 33% of total proved reserves at September 30, 2019.

The Company's PUD reserves increased from 757 Bcfe at September 30, 2018 to 1,018 Bcfe at September 30, 2019. PUD reserves in the Marcellus Shale decreased slightly from 394 Bcfe at September 30, 2018 to 383 Bcfe at September 30, 2019. PUD reserves in the Utica Shale increased from 357 Bcfe at September 30, 2018 to 632 Bcfe at September 30, 2019. The Company's total PUD reserves were 33% of total proved reserves at September 30, 2019, up from 30% of total proved reserves at September 30, 2018.

The decrease in PUD reserves in 2020 of 467 Bcfe is a result of 363 Bcfe in PUD conversions to developed reserves (146 Bcfe from the Marcellus Shale, 214 Bcfe from the Utica Shale and 3 Bcfe from the West Coast region), and 179 Bcfe in PUD reserves removed for seventeen PUD locations, all in the Western Development Area, due to development timing no longer scheduled to meet the five year requirement for proved reserves. Two of these wells removed were in the Marcellus Shale (14 Bcfe) and fifteen were in the Utica Shale (165 Bcfe). These decreases were offset by 7 Bcfe in new PUD reserve additions, 20 Bcfe in

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

upward revisions to remaining PUD reserves and 48 Bcfe in revisions for five PUD locations added back in 2020 (after removing one in 2016 and four in 2017 due to scheduling delays beyond the five year requirement).

The increase in PUD reserves in 2019 of 261 Bcfe is a result of 575 Bcfe in new PUD reserve additions (175 Bcfe from the Marcellus Shale, 398 Bcfe from the Utica Shale and 2 Bcfe from the West Coast region) and 38 Bcfe in upward revisions to remaining PUD reserves, partially offset by 297 Bcfe in PUD conversions to developed reserves (186 Bcfe from the Marcellus Shale, 106 Bcfe from the Utica Shale and 5 Bcfe from the West Coast region), and 55 Bcfe in PUD reserves removed for six PUD locations, two of these wells removed are in the Marcellus (13 Bcfe) and four are in the Utica (42 Bcfe).

The Company invested \$220 million during the year ended September 30, 2020 to convert 363 Bcfe (393 Bcfe after revisions) of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 36% of the net PUD reserves recorded at September 30, 2019. The 30 Bcfe in upward revisions to PUD reserves converted to developed reserves in 2020 were primarily a result of longer completed laterals. In the Appalachian region, 35 of 99 PUD locations were developed and in the West Coast region, all 14 PUD locations were developed.

The Company invested \$246 million during the year ended September 30, 2019 to convert 297 Bcfe (380 Bcfe after positive revisions) of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 39% of the net PUD reserves recorded at September 30, 2018. In fiscal 2019, the Company developed 56 (or 50%) of its well locations with net PUD reserves recorded at September 30, 2018. The majority of these wells were in the Appalachian region. The 83 Bcfe in upward revisions to PUD reserves converted to developed reserves in 2019 were a result of longer completed laterals and improved well performance at PUD locations that were recorded at September 30, 2019.

In 2021, the Company estimates that it will invest approximately \$134 million to develop its PUD reserves. The Company is committed to developing its PUD reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting. Since that rule, and over the last five years, the Company developed 25% of its beginning year PUD reserves in fiscal 2016, 27% of its beginning year PUD reserves in fiscal 2017, 51% of its beginning year PUD reserves in fiscal 2018, 39% of its beginning year PUD reserves in fiscal 2019 and 36% of its beginning year PUD reserves in fiscal 2020.

At September 30, 2020, the Company does not have any proved undeveloped reserves that have been on the books for more than five years at the corporate level, country level or field level. All of the Company's proved reserves are in the United States.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company's oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, in accordance with the SEC's final rule on Modernization of Oil and Gas Reporting, it is based on the 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 and costs adjusted only for existing contractual changes. It assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

The standardized measure is intended instead to provide a means for comparing the value of the Company's proved reserves at a given time with those of other oil- and gas-producing companies than is provided by a simple comparison of raw proved reserve quantities.

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Year Ended September 30		
	2020	2019	2018
	(Thousands)		
United States			
Future Cash Inflows	\$ 6,493,362	\$ 8,738,182	\$ 7,822,855
Less:			
Future Production Costs	3,149,857	2,989,518	2,606,411
Future Development Costs	501,678	797,640	559,707
Future Income Tax Expense at Applicable Statutory Rate	454,553	1,159,882	1,125,910
Future Net Cash Flows	2,387,274	3,791,142	3,530,827
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,164,804	2,054,823	1,810,522
Standardized Measure of Discounted Future Net Cash Flows	\$ 1,222,470	\$ 1,736,319	\$ 1,720,305

The principal sources of change in the standardized measure of discounted future net cash flows were as follows:

	Year Ended September 30		
	2020	2019	2018
	(Thousands)		
United States			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	\$ 1,736,319	\$ 1,720,305	\$ 1,113,046
Sales, Net of Production Costs	(290,975)	(425,773)	(381,775)
Net Changes in Prices, Net of Production Costs	(1,109,101)	(164,428)	541,021
Extensions and Discoveries	4,236	202,683	212,494
Changes in Estimated Future Development Costs	99,884	(69,254)	(43,771)
Purchases of Minerals in Place	170,363	—	—
Sales of Minerals in Place	—	—	(100,816)
Previously Estimated Development Costs Incurred	219,938	245,964	182,348
Net Change in Income Taxes at Applicable Statutory Rate	248,182	21,370	55,558
Revisions of Previous Quantity Estimates	(28,337)	53,777	61,363
Accretion of Discount and Other	171,961	151,675	80,837
Standardized Measure of Discounted Future Net Cash Flows at End of Year	\$ 1,222,470	\$ 1,736,319	\$ 1,720,305

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts(1)	Deductions (2)	Balance at End of Period
Year Ended September 30, 2020					
Allowance for Uncollectible Accounts	\$ 25,788	\$ 12,339	\$ 1,353	\$ 16,670	\$ 22,810
Valuation Allowance for Deferred Tax Assets (3)	\$ —	\$ 63,205	\$ —	\$ —	\$ 63,205
Year Ended September 30, 2019					
Allowance for Uncollectible Accounts	\$ 24,537	\$ 10,184	\$ 1,707	\$ 10,640	\$ 25,788
Valuation Allowance for Deferred Tax Assets (3)	\$ 5,000	\$ —	\$ —	\$ 5,000	\$ —
Year Ended September 30, 2018					
Allowance for Uncollectible Accounts	\$ 22,526	\$ 10,905	\$ 1,967	\$ 10,861	\$ 24,537
Valuation Allowance for Deferred Tax Assets (3)	\$ —	\$ 5,000	\$ —	\$ —	\$ 5,000

- (1) Represents the discount on accounts receivable purchased in accordance with the Utility segment's 2005 New York rate agreement.
- (2) Amounts represent net accounts receivable written-off, as well as a reversal of a valuation allowance, as discussed in footnote (3) below.
- (3) During fiscal 2020, a valuation allowance was recorded against certain state deferred tax assets. During fiscal 2019, there was a \$5.0 million benefit recorded to reverse the valuation allowance established at September 30, 2018 related to the potential sequestration of estimated alternative minimum tax credit refunds as a result of the 2017 Tax Reform Act.

Item 9 *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A *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 September 30, 2020.

Management's Annual Report on Internal Control over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with

GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2020. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework*, published in 2013. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2020.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2020. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

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 September 30, 2020 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B Other Information

None.

PART III

Item 10 Directors, Executive Officers and Corporate Governance

The Company will file the definitive Proxy Statement with the SEC no later than 120 days after September 30, 2020. The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors for Three-Year Terms to Expire in 2024," "Continuing Directors Whose Terms Expire in 2023," and "Continuing Directors Whose Terms Expire in 2022," and is incorporated herein by reference. The information concerning corporate governance will be set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

The Company has adopted a Code of Business Conduct and Ethics that applies to the Company's directors, officers and employees and has posted such Code of Business Conduct and Ethics on the Company's website, www.nationalfuelgas.com, together with certain other corporate governance documents. Copies of the Company's Code of Business Conduct and Ethics, charters of important committees, and Corporate Governance Guidelines will be made available free of charge upon written request to Investor Relations, National Fuel Gas Company, 6363 Main Street, Williamsville, New York 14221.

The Company intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics that applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, and that relates to any element of the code of ethics definition enumerated in paragraph (b) of Item 406 of the SEC's Regulation S-K, by posting such information on its website, www.nationalfuelgas.com.

Item 11 Executive Compensation

The information concerning executive compensation will be set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee," is incorporated herein by reference.

Item 12 *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Equity Compensation Plan Information

The equity compensation plan information will be set forth in the definitive Proxy Statement under the heading “Equity Compensation Plan Information” and is incorporated herein by reference.

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

The information concerning security ownership of certain beneficial owners will be set forth in the definitive Proxy Statement under the heading “Security Ownership of Certain Beneficial Owners and Management” and is incorporated herein by reference.

(b) Security Ownership of Management

The information concerning security ownership of management will be set forth in the definitive Proxy Statement under the heading “Security Ownership of Certain Beneficial Owners and Management” and is incorporated herein by reference.

(c) Changes in Control

None.

Item 13 *Certain Relationships and Related Transactions, and Director Independence*

The information regarding certain relationships and related transactions will be set forth in the definitive Proxy Statement under the headings “Compensation Committee Interlocks and Insider Participation” and “Related Person Transactions” and is incorporated herein by reference. The information regarding director independence is set forth in the definitive Proxy Statement under the heading “Director Independence” and is incorporated herein by reference.

Item 14 *Principal Accountant Fees and Services*

The information concerning principal accountant fees and services will be set forth in the definitive Proxy Statement under the heading “Audit Fees” and is incorporated herein by reference.

PART IV

Item 15 *Exhibits and Financial Statement Schedules*

(a)1. Financial Statements

Financial statements filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)2. Financial Statement Schedules

Financial statement schedules filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)3. Exhibits

All documents referenced below were filed pursuant to the Securities Exchange Act of 1934 by National Fuel Gas Company (File No. 1-3880), unless otherwise noted.

**Exhibit
Number**

**Description of
Exhibits**

3(i) Articles of Incorporation:

Exhibit Number	Description of Exhibits
	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998; Certificate of Amendment of Restated Certificate of Incorporation dated March 14, 2005 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 2012)
3(ii)	By-Laws: National Fuel Gas Company By-Laws as amended March 10, 2016 (Exhibit 3.1, Form 8-K dated March 16, 2016)
4	Instruments Defining the Rights of Security Holders, Including Indentures: - Description of Securities (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 2019) - Indenture, dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796) - Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401) - Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992) - Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992) - Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401) - Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993) - Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999) - Officer's Certificate establishing 4.90% Notes due 2021, dated December 1, 2011 (Exhibit 4.4, Form 8-K dated December 1, 2011) - Officers Certificate establishing 3.75% Notes due 2023, dated February 15, 2023 (Exhibit 4.1.1, Form 8-K dated February 15, 2023) - Officers Certificate establishing 5.20% Notes due 2025, dated June 25, 2015 (Exhibit 4.1.1, Form 8-K dated June 25, 2015) - Officers Certificate establishing 3.95% Notes due 2027, dated September 27, 2017 (Exhibit 4.1.1, Form 8-K dated September 27, 2017) - Officers Certificate establishing 4.75% Notes due 2028, dated August 17, 2018 (Exhibit 4.1.1, Form 8-K dated August 17, 2018) - Officers Certificate establishing 5.50% Notes due 2026, dated June 3, 2020 (Exhibit 4.1.1, Form 8-K dated June 3, 2020)
10	Material Contracts: Fourth Amended and Restated Credit Agreement, dated as of October 25, 2018, among the Company, the Lenders Party Thereto, and JP Morgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 8-K dated October 31, 2018)

<u>Exhibit Number</u>	<u>Description of Exhibits</u>
•	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006)
•	Purchase and Sale Agreement, dated as of May 4, 2020, by and among SWEPI LP, Seneca Resources Company, LLC, NFG Midstream Covington, LLC, National Fuel Gas Midstream Company, LLC and National Fuel Gas Company (Exhibit 10.1, Form 8-K dated May 4, 2020)
•	364-Day Credit Agreement, dated as of May 4, 2020, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent (Exhibit 10.2, Form 8-K dated May 4, 2020)
	Management Contracts and Compensatory Plans and Arrangements:
•	Standard Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and executive officers (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008)
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement between Seneca Resources Company, LLC and John P. McGinnis (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2017)
•	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2011)
•	National Fuel Gas Company 2010 Equity Compensation Plan, as amended and restated December 5, 2018 (Exhibit 10.1, Form 8-K dated March 11, 2019)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2010)
•	National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2012)
•	National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective June 9, 2016 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2016)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005)

Exhibit Number	Description of Exhibits
	• Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005) • National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007) • Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999) • Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999) • National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004) • National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008) • Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010) • Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated August 13, 2015 (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2015) • National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan, as amended and restated March 11, 2020 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2020) • Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2019) • Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2019) • Form of Award Notice for Return on Capital Performance Shares under National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2018) • Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2018) • Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2017) • Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2017) • Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2017)
21	Subsidiaries of the Registrant

<u>Exhibit Number</u>	<u>Description of Exhibits</u>
23	Consents of Experts:
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Company, LLC
23.2	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
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	Additional Exhibits:
99.1	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Company, LLC
99.2	Company Maps
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 years ended September 30, 2020, 2019 and 2018, (ii) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2020, 2019 and 2018 (iii) the Consolidated Balance Sheets at September 30, 2020 and September 30, 2019, (iv) the Consolidated Statements of Cash Flows for the years ended September 30, 2020, 2019 and 2018 and (v) the Notes to Consolidated Financial Statements.
104	Cover Page Interactive Data File (embedded within the Inline XBRL document) • Incorporated herein by reference as indicated. All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K. •• 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 Section 13 or 15(d) 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)**

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

Date: November 20, 2020

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	
<u>/s/ D. F. Smith</u> D. F. Smith	Chairman of the Board and Director	Date: November 20, 2020
<u>/s/ D. H. Anderson</u> D. H. Anderson	Director	Date: November 20, 2020
<u>/s/ B. M. Baumann</u> B. M. Baumann	Director	Date: November 20, 2020
<u>/s/ D. C. Carroll</u> D. C. Carroll	Director	Date: November 20, 2020
<u>/s/ S. C. Finch</u> S.C. Finch	Director	Date: November 20, 2020
<u>/s/ J. N. Jaggars</u> J. N. Jaggars	Director	Date: November 20, 2020
<u>/s/ R. Ranich</u> R. Ranich	Director	Date: November 20, 2020
<u>/s/ J. W. Shaw</u> J. W. Shaw	Director	Date: November 20, 2020
<u>/s/ T. E. Skains</u> T. E. Skains	Director	Date: November 20, 2020
<u>/s/ R. J. Tanski</u> R. J. Tanski	Director	Date: November 20, 2020
<u>/s/ D. P. Bauer</u> D. P. Bauer	President and Chief Executive Officer and Director	Date: November 20, 2020
<u>/s/ K. M. Camiolo</u> K. M. Camiolo	Treasurer and Principal Financial Officer	Date: November 20, 2020
<u>/s/ E. G. Mendel</u> E. G. Mendel	Controller and Principal Accounting Officer	Date: November 20, 2020