National Fuel®

2022 Annual Report

David P. Bauer
President and Chief
Executive Officer

Dear Shareholders,

National Fuel's fiscal 2022 was an outstanding year for the Company, one in which we achieved several significant milestones that position us well for the future. Of note, we completed construction of the FM100 project at our Pipeline & Storage business, achieved record natural gas production and throughput from our Exploration & Production and Gathering businesses, and replaced more than 150 miles of pipeline mains as part of our Utility's long-standing modernization program.

These operational achievements, alongside an improved commodity price backdrop, drove an impressive 37% increase in our adjusted operating results per share from the prior year and further improved the strength of our investment-grade balance sheet. In addition, in line with our strong financial results, we increased our annual dividend rate by 4.4% — making this our 52nd year of consecutive dividend increases and 120th year of uninterrupted dividend payments.

Further, National Fuel took important steps to enhance our environmental, social and governance (ESG) initiatives, positioning our business to play a meaningful role in a lower-carbon economy. In March, we published our inaugural Climate Report, expanding our ESG reporting to better align with the recommendations of the Task Force on Climate-Related Financial Disclosures (TCFD), a well-recognized framework for climate-focused disclosure. Likewise, in September, we published our third annual Corporate Responsibility Report, which describes the Company's progress toward achieving its methane emissions intensity targets, with reductions across the natural gas value chain. In addition, the Company had another outstanding year advancing our safety culture, accomplishing an impressive 20% reduction in our Occupational Safety and Health Administration recordable injury rate over the past three years, excluding cases of workplace COVID transmission.

Improving diversity, equity and inclusion in the workplace continues to be a focus. This year we formed four employee resource groups to support ethnically diverse, veteran, LGBTQ+ and female employees. And with the pandemic behind us, we reenergized our efforts to connect with our communities at deeper levels through corporate volunteerism and stewardship programs. In this regard, National Fuel launched an inaugural "Days of Doing" event in October 2022 in which employees provided more than 1,200 volunteer hours at various nonprofits within our operating footprint.

We believe these undertakings, in conjunction with our high-quality assets, talented workforce and organizational focus on continuous improvement across all aspects of our operations, leave National Fuel well positioned for success in the years ahead.

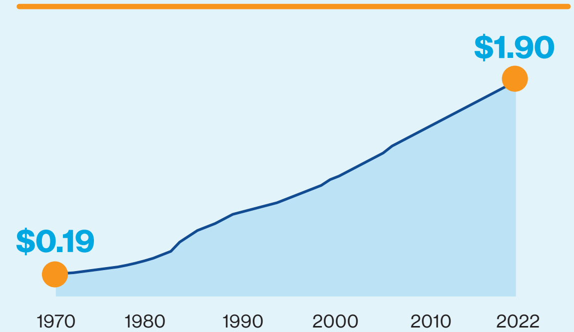
Operational Highlights

Record performance from our Appalachian Development program

In 2022, our Exploration & Production business, Seneca Resources Company, LLC (Seneca), grew its production by approximately 8% to 353 billion cubic feet equivalent (Bcfe), a Company record. On the heels of Seneca's growth, our Gathering business, National Fuel Gas Midstream Company, LLC (Midstream), which gathers 100% of our production, experienced an approximately 11% revenue increase from the prior year, evidencing the value of our integrated approach to Appalachian development. Throughout the year, we continued to leverage our high-quality acreage position within the Utica and Marcellus shales and our valuable marketing portfolio to take advantage of improved natural gas pricing, driving strong operational and financial results.

Fifty-Two Years of Dividend Growth

Annual Rate at Fiscal Year-End



Seneca transitioned to a pure-play natural gas producer in 2022, completing the divestiture of our California properties to Sentinel Peak Resources in June. Just as the spring of 2020 was an optimal time for us to acquire natural gas assets, this was an opportunistic time for Seneca to sell our California assets. These were great assets for National Fuel, generating over $1 billion in cash flow over the past decade that funded significant upstream and midstream growth in Appalachia; however, given the challenging regulatory environment in California, which made it difficult to grow these operations, the time was right to sell. We expect that Sentinel Peak will be a great owner of these assets, maintaining the focus on environmental stewardship that Seneca has long established.

As we move forward, Seneca is focused on its substantial development potential in the Appalachian basin. This tightened focus will continue to position us well for future growth, while significantly improving our expected per-unit cash operating costs and further reducing Seneca's emissions profile.

During fiscal 2022, Seneca made great progress advancing several key environmental and emissions-focused programs across our operations. Seneca's principal focus is reducing methane emissions by replacing natural gas actuated pneumatic devices with compressed air to eliminate vented emissions. Seneca also conducted its first facility-scale monitoring pilot using aerial light detection and ranging (LIDAR) technology to provide real-time assessments of facility emissions, enabling us to identify opportunities to improve our emissions profile.

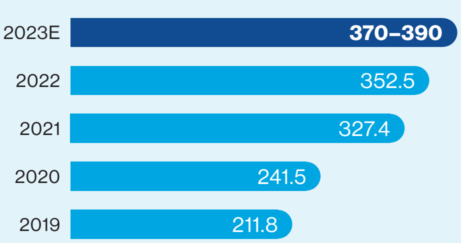
In addition, over the past year, Seneca received multiple responsibly sourced gas certifications, demonstrating our commitment to environmental stewardship and sustainability. In January 2022, Seneca announced the certification of 100% of our natural gas production under Equitable Origin's EO100™ Standard for Responsible Energy Development — a series of rigorous ESG performance metrics. Likewise, in March, Seneca achieved certification under Project Canary's TrustWell™ program for a pilot of 121 wells, all of which received Platinum or Gold ratings. Similarly, in August, Seneca announced its achievement of an "A" certification grade — the highest available certification level — for 100% of its production under MiQ's Standard for Methane Emissions Performance. These accreditations, along with ongoing investments and efforts to achieve emission reduction targets, position National Fuel to differentiate our production in the marketplace.

Looking ahead, in fiscal 2023, we expect to maintain our current activity levels in Appalachia, operating two drilling rigs with a focus on developing our highly economic Eastern Development Area (EDA) assets which, assuming the midpoint of our production guidance, should drive natural gas production growth of 8% over fiscal 2022. Additionally, Seneca plans to deploy a full-time, fully integrated electric hydraulic fracturing fleet in early calendar 2023, which is expected to deliver optimal performance while decreasing emissions.

Seneca employee speaks with a contractor about a Well Done Foundation (WDF) plugging project in Bradford, PA. Seneca provided funding to WDF, a nonprofit aimed at plugging orphaned and abandoned wells, to support WDF's first orphaned well plugging in PA.

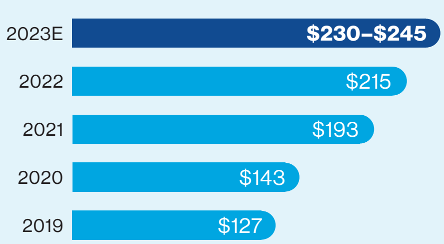
Seneca Resources Production

(Bcfe)



Gathering Revenues

($ millions)



Successful completion of the FM100 project

National Fuel's FERC-regulated Pipeline & Storage subsidiaries, National Fuel Gas Supply Corporation (Supply) and Empire Pipeline, Inc. (Empire), continue to leverage our existing asset footprint to drive growth opportunities in Appalachia. In December 2021, Supply placed into service the $230 million FM100 project. This project, the largest in the Company's history, was completed on time and substantially under budget, which is a testament to the hard work of our dedicated workforce. On an annual basis, we expect the FM100 project to add approximately $50 million in revenues to our Pipeline & Storage business, while also providing, in conjunction with a companion third-party pipeline expansion, 330,000 dekatherms per day (Dth/d) of high-value firm transportation capacity for Seneca's production.

Supply employee inspects an upgraded compressor unit in Mercer County, PA. New unit equipment helps to improve efficiency and lower emissions.

As we move into fiscal 2023, we will continue to pursue opportunities to expand our pipeline system, leveraging our interconnectivity to other long-haul pipelines and proximity to producers, while further investing in the safety, integrity and reliability of our transmission and storage assets through our ongoing modernization program. Over the last five years, Supply and Empire have invested more than $450 million on safety and modernization efforts, helping to drive a 24% reduction in methane intensity in calendar year 2021 from 2020, when methane intensity reduction targets were established at each of our businesses.

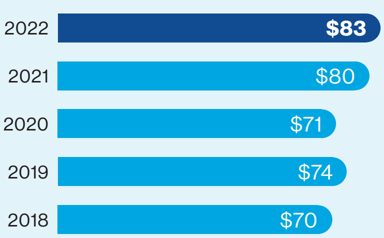
Significant progress in Utility modernization

Our Utility business, National Fuel Gas Distribution Corporation (Distribution), remains focused on safely and reliably providing natural gas service to more than 2 million residents in Western New York and Northwestern Pennsylvania. Over the past five years, our Utility has invested approximately $380 million on system modernization efforts, replacing 770 miles of pipeline mains over this period. These investments are a win-win for our customers and the Company, furthering the safety and reliability of our distribution network while driving additional reductions in EPA-reported greenhouse gas (GHG) emissions. Since 1990, our modernization program has driven a more than 65% reduction in delivery system GHG emissions, keeping the Company on track to achieve its targeted 75% reduction by 2030 and 90% reduction by 2050, which exceeds the requirements of New York State's Climate Leadership and Community Protection Act.

As we move ahead, we believe our multi-pronged approach to reducing our carbon footprint — focused on operational emissions reductions, energy conservation and embracing new and emerging technology, as well as leveraging our highly reliable and weather-hardened pipeline network for the delivery of low and no-carbon fuels — provides a solid foundation for National Fuel's long-term role in the energy complex. We expect that Distribution will continue to make significant investments

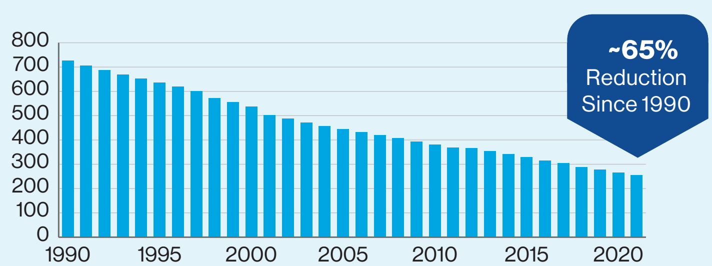
Utility Investment in Safety

(Fiscal Year — $ millions)



Utility Delivery System GHG Emissions

*(Calendar Year - Thousand Metric Tons, CO2e)**



**EPA Subpart W, using AR5 Global Warming Potential* to ensure the long-term safety, reliability and resilience of its system, while remaining steadfastly committed to the sustainability of our operations.

Our Continued and Important Role in the Energy Complex

The importance of an "all-of-the-above" approach

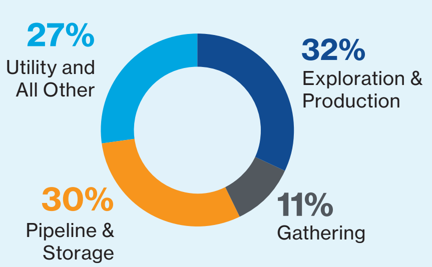
The affordability, reliability and security offered by natural gas is unmatched by any other source of energy today. Fortunately, the United States has an abundant supply of this low-cost and low-emissions-intensity energy readily available in the Marcellus and Utica shales. Natural gas and its safe, reliable and resilient delivery network, should continue to be a central component in an "all-of-the-above" approach to energy policy. One need only look to the challenges facing Europe to see the perils of going "all-in" on intermittent resources.

Nevertheless, we continue to see policymakers in New York and elsewhere pushing the narrative that growth in wind and solar alone can meet the needs of a fully electric world — including for winter heating in cold climates like Buffalo — without sacrificing affordability and reliability. They fully believe the electric grid can nearly triple in size without impacting cost, and they have complete faith that massive amounts of dispatchable, emissions-free generation solutions will be developed when no such technologies exist today at scale. The gap between aspirations and reality is truly remarkable.

Internationally, there is a growing and renewed appreciation for the role of natural gas. The European Union, which is several years ahead of the U.S. in its efforts to decarbonize its economy, now has committed to building new natural gas facilities and included natural gas to its taxonomy of "green energy."

Balance and Diversification

Percentage of Consolidated Total Assets by Segment



National Fuel Utility employees tour a customer site of facilities that control the blending of hydrogen and natural gas to demonstrate reduced boiler emissions in Tonawanda, NY.

I am optimistic that one day the U.S. will reach this same level of appreciation and affirm natural gas as an essential component of an "all-of-the-above" approach to energy that ensures reliability, affordability and security.

The natural gas industry stands ready and willing to do its part to help alleviate the ongoing energy challenge both domestically and globally. I firmly believe increased natural gas production and pipeline infrastructure will be needed if the U.S. is serious about achieving its emission reduction goals and ensuring energy security. National Fuel is well positioned to play a long-term role in developing this resource and building the facilities needed to move critical energy supplies to markets.

Our Bright Future

Fiscal 2022 was undoubtedly a great year for National Fuel — a year which further built upon the strong foundation of our business and positioned the Company for continued success. As we look ahead, we expect that our significant footprint of high-quality assets in one of the lowest-emissions-intensity basins in the world will provide the Company with meaningful opportunities to further grow the business.

Our strong operational execution has laid the groundwork for National Fuel to generate significant and durable free cash flow across our businesses. We believe this puts us in the very enviable position in which we can simultaneously grow the business, strengthen our investment-grade balance sheet and increase the amount of capital we return to shareholders through our dividend, all of which we expect will deliver considerable value to shareholders over the long-term.

David P Bauer

David P. Bauer
President and Chief Executive Officer
January 6, 2023

Directors

From left to right:

David H. Anderson
President and Chief Executive Officer of Northwest Natural Holding Company and Northwest Natural Gas Company

David P. Bauer
President and Chief Executive Officer of National Fuel Gas Company

Barbara M. Baumann
President and Owner of Cross Creek Energy Corporation

David C. Carroll
Former President and Chief Executive Officer of GTI Energy

Steven C. Finch
President, Manufacturing and Director of Community Engagement at Viridi Parente, Inc.

Joseph N. Jaggers
Former President, Chairman, and Chief Executive Officer of Jagged Peak Energy Inc.

Rebecca Ranich
Former Director at Deloitte Consulting, LLP

Jeffrey W. Shaw
Former Director and Chief Executive Officer of Southwest Gas Corporation

Thomas E. Skains
Former President, Chairman, and Chief Executive Officer of Piedmont Natural Gas Company, Inc.

David F. Smith
Chairman of the Board and former Chief Executive Officer of the Company

Ronald J. Tanski
Former President and Chief Executive Officer of the Company

Officers

David P. Bauer
President and Chief Executive Officer

Ronald C. Kraemer
Chief Operating Officer
President, National Fuel Gas Supply Corporation and Empire Pipeline, Inc.

Donna L. DeCarolis
President, National Fuel Gas Distribution Corporation

Justin I. Loweth
President, Seneca Resources Company, LLC and National Fuel Gas Midstream Company, LLC

Karen M. Camiolo
Treasurer and Principal Financial Officer

Elena G. Mendel
Controller and Principal Accounting Officer

Martin A. Krebs
Chief Information Officer

Sarah J. Mugel
General Counsel, Secretary and Corporate Responsibility Officer

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, 2022

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

For the Transition Period from to
Commission File Number 1-3880

National Fuel Gas Company

(Exact name of registrant as specified in its charter)

New Jersey	**13-1086010**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6363 Main Street	
Williamsville, New York	**14221**
(Address of principal executive offices)	*(Zip Code)*

(716) 857-7000
(Registrant's telephone number, including area code)

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

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

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 $6,253,478,000 as of March 31, 2022.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2022: 91,485,294 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2023 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2022, 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

IRS Internal Revenue Service

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

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.

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

FERC 7(c) application An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.

Firm transportation and/or storage The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.

GAAP Accounting principles generally accepted in the United States of America

Goodwill An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.

Hedging A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.

Hub Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.

ICE Intercontinental Exchange. An exchange which maintains a futures market for crude oil and natural gas.

Interruptible transportation and/or storage The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.

LDC Local distribution company

LIBOR London Interbank Offered Rate

LIFO Last-in, first-out

Marcellus Shale A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.

Mbbl Thousand barrels (of oil)

Mcf Thousand cubic feet (of natural gas)

MD&A Management's Discussion and Analysis of Financial Condition and Results of Operations

MDth Thousand decatherms (of natural gas)

MMBtu Million British thermal units (heating value of one decatherm of natural gas)

MMcf Million cubic feet (of natural gas)

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.

OPEB Other Post-Employment Benefit

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

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.

SOFR Secured Overnight Financing Rate

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/WNA Weather normalization clause/adjustment; 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, 2022

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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, storage 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 both existing and new 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 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, primarily natural gas in the Appalachian region of the United States. At September 30, 2022, Seneca had proved developed and undeveloped reserves of 4,170,662 MMcf of natural gas and 250 Mbbl 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, and Empire provides storage service (via lease with Supply Corporation) to a nonaffiliated company.

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 754,000 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 for 2021 and 2020. This division marketed timber from Appalachian land holdings. On August 5, 2020, the Company entered into a purchase and sale agreement to sell substantially all timber and other assets, which at September 30, 2020, accounted for the Company's ownership of approximately 95,000 acres of timber property and management of approximately 2,500 additional acres of timber cutting rights. The transaction closed on December 10, 2020.

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

Revenues from three customers of the Company's Exploration and Production segment, exclusive of hedging losses transacted with separate parties, represented approximately $850 million, or 38.9%, of the Company's consolidated revenue for the year ended September 30, 2022. These three customers were also customers of the Company's Pipeline and Storage segment, accounting for an additional $15 million, or 0.7%, of the Company's consolidated revenue for the year ended September 30, 2022.

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 and storage 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, and other regulators, 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 contributed net income of $306.1 million in 2022.

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 $102.6 million in 2022.

The Pipeline and Storage segment generated approximately 30% of its revenues in 2022 from services provided to the Utility segment or Exploration and Production segment.

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 $101.1 million in 2022.

The Gathering segment generated approximately 94% of its revenues in 2022 from services provided to the Exploration and Production segment.

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 $68.9 million in 2022.

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 $12.7 million in 2022.

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 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 N — 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, in large part, produced by Seneca in the Appalachian region of the United States.

Natural gas is the principal raw material for the Utility segment. In 2022, the Utility segment purchased 76.0 Bcf of gas (including 74.2 Bcf for delivery to retail customers and 1.8 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 48% of these purchases. Purchases of gas in the spot market (contracts of one month or less) accounted for 52% of the Utility segment’s 2022 purchases. Purchases from DTE Energy Trading, Inc. (33%), Emera Energy Services, Inc. (12%), Chevron Natural Gas (8%), EQT Energy, LLC (7%), Vitol Inc. (6%), Tenaska Marketing Ventures (6%), and Shell Energy North America US (6%), accounted for nearly 78% of the Utility segment's 2022 gas purchases. No other producer or supplier provided the Utility segment with more than 5% of its gas requirements in 2022. The Utility segment does not directly purchase gas from affiliates.

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 reliability and affordability, along with 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 natural gas producers and marketers with respect to sales of natural gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other 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 prospect and partnership 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 that provide access to these supplies and to premium off-system markets. 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 natural gas to key markets within New York State, the northeastern United States and Canada.

Competition: The Gathering Segment

The Gathering segment provides gathering services for Seneca and, to a lesser extent, other producers. It 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 8% 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, natural gas retains its competitive position despite recent commodity pricing.

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. In addition to the Inflation Reduction Act, 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 largely 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 delivery revenues calculated at normal temperatures will be largely 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 competitive benefits, 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 recently published 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 2,132 full-time employees at September 30, 2022.

As of September 30, 2022, 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 into February 2025, as well as with collective bargaining units in Pennsylvania into April 2026.

Safety

Safety is one of the Company's guiding principles. In managing the business, the Company focuses on the safety of its employees and contractors 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's voluntary attrition rate (not including retirements and excluding the severance related to the sale of Seneca's assets in California) was 8%. Additionally, throughout the COVID-19 pandemic, the Company did not institute 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 market-competitive benefits packages to employees of its subsidiaries. The Company's benefits package options may vary depending on type of employee 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 subsidiaries to discuss career pathing and employee development.

Diversity, Equity 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. As such, the Company approaches diversity from the top-down, which is reflected in the makeup of our Board of Directors and senior leadership team: three out of eleven directors are diverse, and four of the Company's eight designated executive officers are women. The Company's Corporate Governance Guidelines incorporate the "Rooney Rule." As a result, when identifying independent director candidates for nomination to the Board, the Nominating/Corporate Governance Committee is committed to including in any initial candidate pool qualified racially, ethnically and/or gender diverse candidates. Beginning in fiscal 2021, the Compensation Committee adopted specific diversity and inclusion performance goals as part of the Company's Annual at Risk Compensation Incentive Plan and Executive Annual Compensation Incentive Program to link executive compensation to the Company's focus on diversity.

During fiscal 2022, the Company furthered numerous initiatives to increase the diversity of our workforce and create a more inclusive environment. The Company's Director of Diversity and Inclusion ("D&I Director") continued to spearhead diversity and inclusion initiatives across the organization. Additional resources were added to the Diversity and Inclusion team with the creation of a Diversity and Inclusion Specialist ("D&I Specialist") role to assist and expand the Company's proactive efforts of creating a more inclusive organization. These efforts include initiatives to focus on diversity when making hiring and promotional decisions. To attract diverse candidates, the Company works with community groups and organizations to help promote awareness of our job opportunities within diverse communities. The D&I Director maintains close partnerships with the employment teams, cultivates the Company's relationships with community organizations, and focuses on initiatives to attract diverse candidates, vendors and suppliers. The executive team receives a monthly report about the composition of the Company's salaried applicant pools to encourage the recruiting team to focus recruiting in diverse communities and identify resources needed to do so. The Company has also focused on encouraging diverse suppliers to receive the necessary certifications to participate in the industry and has added new diverse suppliers to its list of vendors in an effort to promote diversity.

The D&I Director and D&I Specialist also spearhead inclusion initiatives throughout the organization. To promote a more inclusive work environment, the Company has continued to provide training opportunities to employees relating to Unconscious Bias, Inclusivity, and Micro-aggressions. In addition, four new Employee Resource Groups, focused towards ethnically diverse, veteran, LGBTQ and female employees, were developed. These Employee Resource Groups provide an opportunity to engage and connect with underrepresented employees, and each group has an executive sponsor which helps facilitate communication directly to senior management. 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. This policy is mailed to employees annually with an employee survey, and employees must acknowledge that they have received the policy. The Company reiterates its commitment to a harassment free workplace through this process, as well as through prevention training for employees. Annually, the Company's Chief Executive Officer reinforces the Company's commitment to harassment prevention and equal employment opportunity by signing corporate Equal Employment Opportunity and Non-Discrimination and Anti-Harassment policy statements. These statements are then displayed at Company locations, included in employee handbooks, and discussed with new hires during their onboarding process.

Executive Officers of the Company as of November 15, 2022(1)

Name and Age (as of November 15, 2022)	Current Company Positions and Other Material Business Experience During Past Five Years
David P. Bauer (53)	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.
Donna L. DeCarolis (63)	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.
Ronald C. Kraemer (66)	Chief Operating Officer of the Company since March 2021, 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.
Karen M. Camiolo (63)	Treasurer and Principal Financial Officer of the Company since July 2019. Treasurer of Seneca Resources Company since July 2019. Ms. Camiolo previously served as Treasurer of Distribution Corporation, Supply Corporation, Empire and Midstream Company from July 2019 through June 2021. 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. Controller of Midstream Company from April 2013 through June 2019. Controller of Empire from June 2007 through June 2019. Controller of Distribution Corporation and Supply Corporation from April 2004 through June 2019.
Elena G. Mendel (56)	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.
Martin A. Krebs (52)	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' prior employers are not subsidiaries or affiliates of the Company.
Sarah J. Mugel (58)	Corporate Responsibility Officer of the Company since April 2022. 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.
Justin I. Loweth (44)	President of Midstream Company since April 2022 and President of Seneca Resources Company since May 2021. Mr. Loweth previously served as Senior Vice President of Seneca Resources Company from October 2017 through April 2021.

(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. Turmoil in credit markets 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 existing 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, taking into account the incremental issuance, and using a pro forma balance sheet as of the last day of the 12-month period used in the interest coverage test, the Company must maintain a ratio of long-term debt to consolidated assets (as defined under the 1974 indenture) of not more than 60%. The 1974 indenture defines consolidated assets as total assets less a number of items, including current and accrued liabilities. Depending on their magnitude, factors that reduce the Company’s operating income and/or total assets, including impairments (i.e., write-downs) of the Company’s natural gas properties, or that increase current and accrued liabilities, like short-term borrowings and "out of the money" derivative financial instruments, could contribute to the Company’s inability to meet the interest coverage test or debt-to-assets ratio.

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, Inc. A downgrade in the Company's credit ratings could increase borrowing costs, restrict or eliminate access to commercial paper markets, negatively impact the availability of capital from uncommitted sources, and require the Company’s subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. Additionally, $1.1 billion 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 $1.1 billion, 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.

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

Climate change, and the laws, regulations and other initiatives to address climate change, may impact the Company’s financial results. In early 2021, the U.S. rejoined the Paris Agreement, the international effort to establish emissions reduction goals for signatory countries. Under the Paris Agreement, signatory countries are expected to submit their nationally determined contributions to curb greenhouse gas emissions and meet the agreed temperature objectives every five years. On April 22, 2021, the federal administration announced the U.S. nationally determined contribution to achieve a fifty to fifty-two percent reduction from 2005 levels in economy-wide net greenhouse gas pollution by 2030. In addition to the federal reentry into the Paris

Agreement, state and local governments, non-governmental organizations, investment firms, 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. Executive orders from the federal administration, in addition to federal, state and local legislative and regulatory initiatives proposed or adopted 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 and/or production of gas, establishment of a carbon tax and/or methane fee, lack of support for system modernization, as well as accelerated depreciation of assets and/or stranded assets.

Federal and state legislatures have from time to time considered bills that would establish a cap-and-trade program, methane fee or carbon tax to incent the reduction of greenhouse gas emissions. For example, in August 2022, the federal Inflation Reduction Act was signed into law, which includes a methane charge that is expected to be applicable to the reported annual methane emissions of certain oil and gas facilities, above specified methane intensity thresholds, starting in calendar year 2024. In addition, the New York State legislature, in early 2021, proposed a bill known as the Climate and Community Investment Act, which proposed an escalating fee starting at $55 per short ton of carbon dioxide equivalent on any carbon-based fuels sold, used or brought into the state. That bill did not pass, but similar legislation may be proposed in the future. If the Company becomes subject to new or revised cap-and-trade programs, methane charges, fees for carbon-based fuels or other similar costs or charges, the Company may experience additional costs and incremental operating expenses, which would impact our future earnings and cash flows.

A number of states have also 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 natural gas industry which has resulted in permitting changes with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines. In addition, the NYPSC initiated a proceeding to consider climate-related financial disclosures at the utility operating level, and in 2019, the New York State legislature passed the CLCPA, which created emission reduction and electric generation mandates, and could ultimately impact the Utility segment’s customer base and business. Pursuant to the CLCPA, New York's Climate Action Council issued for comment a draft scoping plan that includes recommendations to decommission substantial portions of the natural gas system and curtail use of natural gas and natural gas appliances.

Legislation or regulation that aims to reduce greenhouse gas emissions could also include natural gas bans, greenhouse gas emissions limits and reporting requirements, carbon taxes and/or similar fees on carbon dioxide, methane or equivalent emissions, restrictive permitting, increased efficiency standards requiring system remediation and/or changes in operating practices, and incentives or mandates to conserve energy or use renewable energy sources. NYDEC finalized its Part 203 Oil and Gas Sector Rule in March 2022, which significantly increases leak detection and repair inspections, recordkeeping, reporting, and notification requirements for multiple sources along city gates, transmission pipelines, compressor stations, storage facilities, and gathering lines.

Additionally, the trend toward increased energy conservation, change in consumer behaviors, 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.”

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 natural gas industry could have an adverse effect on Company operations.

Organized opposition to the natural gas industry, including exploration and production activity, pipeline expansion and replacement projects, and the extension and continued operation of natural gas distribution systems, may continue to increase as a result of, among other things, safety incidents involving natural 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 natural gas, 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. There are also increasing litigation risks associated with climate change concerns and related disclosures. Increased litigation 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 planned distribution, gathering, and transmission pipeline and storage facilities, as well as the expansion and replacement of existing facilities, and the development of new natural gas wells, 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 Company’s acquisition, expansion or renewal of rights-of-way or land rights on a timely basis and on acceptable terms. Any delay in project development or 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 or gathering facility completion 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 dividends to the Company 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 could adversely affect the Company’s revenues and cash flows or restrict its future growth. Additionally, supply chain disruptions, and the associated costs and inflation related thereto, could have an impact on the Company's operations. Economic conditions in the Company’s utility service territories, along with legislative and regulatory prohibitions and/or limitations on terminations of service, also impact its collections of accounts receivable. Customers of the Company’s Utility segment may have particular trouble paying their bills during periods of declining economic activity, high inflation, or high commodity prices, potentially resulting in increased bad debt expense and reduced earnings. 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 natural 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. Certain customers of the Company's Exploration and Production segment can represent a concentrated risk during times of high commodity prices and high hedge losses. Any of these events or circumstances could have or contribute to 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.

Loans to the Company under its committed credit facilities may be alternate base rate loans or term SOFR loans. SOFR is a reference rate (the Secured Overnight Financing Rate) published by the Federal Reserve Bank of New York. SOFR is one available replacement for LIBOR (the London Interbank Offered Rate), which the U.K.'s Financial Conduct Authority is phasing out as a benchmark. The change from LIBOR to SOFR could expose the Company's borrowings to less favorable rates. If the change to SOFR results in increased interest rates or if the Company's lenders have increased costs due to the change, then the Company's debt that uses benchmark rates could be affected and, in turn, the Company's cash flows and interest expense could be adversely impacted.

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

Financial results in the Company's Exploration and Production segment are materially dependent on prices received for its natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, and gathering natural gas. Natural gas prices can be volatile and can be affected by various factors, including weather conditions, natural disasters, 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 and liquefaction facilities, regional and global levels of supply and demand, energy conservation measures, and government regulations. The Company sells the natural 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 and/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 natural 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 future 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 natural gas at different geographic locations could adversely impact the Company. For example, if the price of natural gas at a particular receipt point on the Company's pipeline system increases relative to the price of natural gas at other locations, then the volume of natural gas received by the Company at the relatively more expensive receipt point may decrease, or the Company may need to discount the approved tariff rate for that transportation path in the future in order to maintain the existing volumes on its system. Changes in price differentials can cause shippers to seek alternative lower priced natural 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 natural 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 natural gas storage services driven by that price differential could decrease. These changes could adversely affect future revenues, cash flows and results of operations.

In the Company's Utility segment, during periods when natural gas prices are significantly higher than historical levels, customers may have trouble paying the resulting higher bills, which could increase bad debt expenses and ultimately reduce earnings. Additionally, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of the Company's capital resources.

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

To protect itself to some extent against price volatility and to lock in fixed pricing on natural 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 a substantial majority of the Company's expected energy production over the course of 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.

The nature of these hedging contracts could lead to potential liquidity impacts in scenarios of significantly increased natural gas prices if the Company has hedged its current production at prices below the current market price. Hedging collateral deposits represent the cash, letters of credit, or other eligible instruments held in Company funded margin accounts to serve as collateral for hedging positions used in the Company's Exploration and Production segment. A significant increase in natural gas prices may cause the Company's outstanding derivative instrument contracts to be in a liability position creating margin calls on the Company's hedging arrangements, which could require the Company to temporarily post significant amounts of cash collateral with our hedge counterparties. That collateral could be in excess of the Company's available short-term liquidity under its committed credit facility and other uncommitted sources of capital, leading to potential default under certain of its hedging arrangements. That interest-bearing cash collateral is returned to us in whole or in part upon a reduction in forward market prices, depending on the amount of such reduction, or in whole upon settlement of the related derivative contract.

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.

In the Exploration and Production segment, under the Company's hedging guidelines, 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 natural 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 natural 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 natural 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 natural gas prices, production and development costs, severance and excise taxes, and capital expenditures. Changes in natural gas prices impact the quantity of economic natural gas reserves. 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 natural 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 natural 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 natural 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 natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating natural 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 natural 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 natural gas that are ultimately recovered, the timing of the recovery of natural 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 natural 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 natural 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 authoritative accounting and reporting guidance 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. In addition, because an impairment results in a charge to retained earnings, it lowers the Company's total capitalization, all other things being equal, and increases the Company's debt to capitalization ratio. As a result, an impairment can impact the Company's ability to maintain compliance with the debt to capitalization covenant set forth in its credit facilities. For example, for the fiscal year ended September 30, 2020 and the quarter ended December 31, 2020, the Company recognized non-cash, pre-tax impairment charges on its oil and natural gas properties of $449.4 million and $76.2 million, respectively.

OPERATIONAL RISKS

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.

Our businesses depend on natural gas gathering, storage, and transmission facilities, which, if unavailable, could adversely affect the Company's results of operations, financial condition, and cash flows.

Our businesses depend on natural gas gathering, storage, and transmission facilities, including third-party midstream facilities that are not within our control. Our Exploration and Production and Utility segments have entered into long-term agreements with midstream providers for natural gas gathering, storage, and/or transportation services. The disruption or unavailability of the midstream facilities required to provide these services, due to maintenance, mechanical failures, accidents, weather, regulatory requirements and/or other operational hazards, could negatively impact our ability to market and/or deliver our products, especially if such disruption were to last for an extended period of time. In addition, any substantial disruptions to the services provided by our midstream providers could cause us to curtail a significant amount of our production or could impair our ability to deliver natural gas to our utility customers and could have a material adverse effect on the Company's results of operations, financial condition, and cash flows. Furthermore, as substantially all of our production is transported from the well pad to interconnections with various FERC-regulated pipelines though our affiliated gathering facilities, such a production curtailment could result in significantly reduced throughput on those facilities, adversely affecting revenues and cash flows of our Gathering business.

The disruption of the Company's information technology and operational technology systems, including third party attempts to breach the Company's network security, could adversely affect the Company's financial results.

The Company relies on information technology and operational technology systems to process, transmit, and store information, to manage and support a variety of business processes and activities, and to comply with regulatory, legal, and tax requirements. The Company's information technology and operational technology systems, some of which are dependent on services provided by third parties, may be vulnerable to damage, interruption, or shutdown due to any number of causes outside of our control such as catastrophic events, natural disasters, fires, power outages, systems failures, telecommunications failures, and employee error or malfeasance. In addition, the Company's information technology and operational 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, regulations and directives. While the Company employs reasonable and appropriate controls to maintain and protect its information technology and operational technology systems, the Company may be vulnerable to material disruptions, material security breaches, lost or corrupted data, programming errors and employee errors and/or malfeasance that could lead to interruptions to the Company's business operations or the unauthorized access, use, disclosure, modification or destruction of 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 system disruptions or breaches, including restoration of customer service and enhancement of information technology and operational technology systems.

The Company seeks to prevent, detect and investigate 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 disruptions to services or 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 a material disruption or breach were to occur, the Company's operations, earnings, cash flows and financial condition could be adversely affected to the extent not fully covered by such insurance.

The amount and timing of actual future natural 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 natural gas, including numerous uncertainties inherent in estimating quantities of proved natural 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 natural 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, completion crew and related equipment availability, geology, and other factors. Drilling for natural 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, competition and cost to acquire mineral rights, 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.

The physical risks associated with climate change may adversely affect the Company's operations and financial results.

Climate change could create acute and/or chronic physical risks to the Company's operations, which may adversely affect financial results. Acute physical risks include more frequent and severe weather events, which may result in adverse physical effects on portions of U.S. natural gas infrastructure, and could disrupt the Company's supply chain and ultimately its operations. Disruption of production activities, as well as natural gas transportation and distribution systems, could result in reduced operational efficiency, and customer service interruption. Severe weather events could also cause physical damage to facilities, all of which could lead to reduced revenues, increased insurance premiums or increased operational costs. To the extent the Company's regulated businesses are unable to recover those costs, or if the recovery of those costs results in higher rates and reduced demand for Company services, the Company's future financial results could be adversely impacted. Chronic physical risks include long-term shifts in climate patterns resulting in new storm patterns or chronic increased temperatures, which could cause demand for gas to increase or decrease as a result of warmer weather and less degree days, and adversely impact the Company's future financial results.

Disputes with collective bargaining units representing the Company's workforce, and work stoppage (e.g. strike or lockout), could adversely affect the Company's operations as well as its financial results.

Approximately half of the Company's active workforce is represented by collective bargaining units in New York and Pennsylvania. These labor agreements are negotiated periodically, and therefore, the Company is subject to the risk that such agreements may not be able to be renewed on reasonably satisfactory terms, on anticipated timelines, or at all. In connection with the negotiation of such collective bargaining agreements, or in future matters involving collective bargaining units representing the Company's workforce, the Company could experience, among other things, strikes, work stoppages, slowdowns or lockouts, which could cause a disruption of the Company's operations and have a material adverse effect on the Company's results of operations and financial condition.

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 natural gas transmission and storage 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 and/or cash flows may decrease.

Environmental regulation significantly affects the Company's business.

The Company's business operations are subject to federal, state, and local laws, regulations and agency policies relating to environmental protection including obtaining and complying with permits, leases, approvals, consents and certifications from various governmental and permit authorities. These laws, regulations and policies 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 natural 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.

Various state legislative and regulatory initiatives regarding the exploration and production business have been proposed or adopted in the northeast United States affecting the Marcellus and Utica Shale gas plays. These initiatives include potential new or updated statutes and regulations governing the drilling, casing, cementing, testing, monitoring and abandonment 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 natural 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 delayed recovery or disallowance of purchased gas costs incurred by the Utility segment.

Tariff rate schedules in each of the Utility segment's service territories contain purchased natural gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased natural gas. Assuming those rate adjustments are granted, increases in the cost of purchased natural 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 natural gas. Extreme weather events, variations in seasonal weather, and other events disrupting supply and/or demand could cause the Company to experience unforeseeable and unprecedented increases in the costs of purchased natural gas. Any prudently incurred natural gas costs could be subject to deferred recovery if regulators determine such costs are detrimental to customers in the short-term. Furthermore, there is a risk of disallowance of full recovery of these costs if regulators determine that Distribution Corporation was imprudent in making its natural gas purchases. Any material delayed recovery or disallowance of purchased natural 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, and/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 $6.6 billion at September 30, 2022. The Exploration and Production segment constitutes 31.2% of this investment, and is primarily located in the Appalachian region of the United States. Approximately 56.1% 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 12.6% of the Company’s investment in net property, plant and equipment, and is located in northwestern and central 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 modernize transmission and distribution facilities for customers in New York and Pennsylvania. Net property, plant and equipment has increased $1.9 billion, or 40.5%, since September 30, 2017. The five year increase is net of impairments of oil and gas producing properties recorded in 2020 and 2021 ($449 million and $76 million, respectively).

The Exploration and Production segment had a net investment in property, plant and equipment of $2.1 billion at September 30, 2022.

The Pipeline and Storage segment had a net investment of $2.0 billion in property, plant and equipment at September 30, 2022. Transmission pipeline represents 37% of this segment’s total net investment and includes 2,301 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 13% of this segment’s total net investment and consist of 387 miles of pipeline, as well as 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. Net investment in storage facilities includes $79.7 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 34 compressor stations with 262,393 installed horsepower that represent 32% of this segment’s total net investment in property, plant and equipment.

The Pipeline and Storage segment's facilities provided the capacity to meet Supply Corporation’s 2022 peak day sendout for transportation service of 2,092 MMcf, which occurred on January 10, 2022. Withdrawals from storage of 718 MMcf provided approximately 34% 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, 2022. Gathering lines and related compressor stations represent substantially all of this segment’s total net investment, including 368 miles of pipelines utilized to move Appalachian production (including Marcellus and Utica shales) to various transmission pipeline receipt points. The Gathering segment has 25 compressor stations with 119,980 installed horsepower.

The Utility segment had a net investment in property, plant and equipment of $1.7 billion at September 30, 2022. The net investment in its gas distribution network (including 15,040 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, 2022.

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 reserves in the Appalachian region of the United States. 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 N — Supplementary Information for Oil and Gas Producing Activities. Note N sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2022, 2021 and 2020 reserves shown in Note N 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 petroleum engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Note N discusses the qualifications of the Company's petroleum 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 3,723 Bcf at September 30, 2021 to 4,171 Bcf at September 30, 2022. This increase is attributed to extensions and discoveries of 838 Bcf and revisions of previous estimates of 3 Bcf, partially offset by production of 343 Bcf. Upward revisions included 3 Bcf of price-related revisions and 13 Bcf of revisions related to positive performance improvements including reduced operating expenses. The additions and upward revisions were partially offset by divestures of 50 Bcf as well as downward revisions of 13 Bcf from the removal of 1 PUD location related to pad layout changes. The Company has no near term plans to develop the reserves at this PUD location.

Seneca's proved developed and undeveloped oil reserves decreased from 21,537 Mbbl at September 30, 2021 to 250 Mbbl at September 30, 2022. The decrease of 21,287 Mbbl is attributed to production of 1,604 Mbbl and the sale of Seneca's West Coast region (i.e., California assets) of 20,766 Mbbl. These decreases were partially offset by positive performance revisions of 787 Mbbl and extensions and discoveries of 296 Mbbl.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 3,853 Bcfe at September 30, 2021 to 4,172 Bcfe at September 30, 2022. This increase is attributed to extensions and discoveries of 839 Bcfe and upward revisions of previous estimates of 8 Bcfe, partially offset by production of 353 Bcfe and divestures, primarily from the sale of the West Coast region (i.e., California assets), of 175 Bcfe.

Seneca's proved developed and undeveloped natural gas reserves increased from 3,325 Bcf at September 30, 2020 to 3,723 Bcf at September 30, 2021. This increase was attributed to extensions and discoveries of 689 Bcf and revisions of previous estimates of 23 Bcf, partially offset by production of 314 Bcf. Upward revisions included 74 Bcf of price-related revisions and 29 Bcf of revisions related to positive performance improvements including reduced operating expenses. Downward revisions of 80 Bcf from the removal of 8 PUD locations were due to continued integration of the Tioga assets acquired in July 2020, as well as other operational optimizations that resulted in pad layout and development schedule changes.

Seneca's proved developed and undeveloped oil reserves decreased from 22,100 Mbbl at September 30, 2020 to 21,537 Mbbl at September 30, 2021. The decrease of 563 Mbbl was attributed to production of 2,235 Mbbl and downward revisions of previous estimates of 579 Mbbl, partially offset by positive price-related revisions of 1,210 Mbbl and extensions and discoveries of 1,041 Mbbl, primarily occurring in the West Coast region.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 3,458 Bcfe at September 30, 2020 to 3,853 Bcfe at September 30, 2021. This increase was attributed to extensions and discoveries of 696 Bcfe and upward revisions of previous estimates of 26 Bcfe, partially offset by production of 327 Bcfe.

At September 30, 2022, the Company's Exploration and Production segment had delivery commitments for natural gas production of 2,390 Bcf. The Company expects to meet those commitments through the future production 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					
	2022		2021		2020	
United States						
Appalachian Region						
Average Sales Price per Mcf of Gas	$ 5.03	(1)	$ 2.46	(1)	$ 1.75	(1)
Average Sales Price per Barrel of Oil	$ 97.82		$ 48.02		$ 45.69	
Average Sales Price per Mcf of Gas (after hedging)	$ 2.69		$ 2.22		$ 2.05	
Average Sales Price per Barrel of Oil (after hedging)	$ 97.82		$ 48.02		$ 45.69	
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.68	(1)	$ 0.67	(1)	$ 0.68	(1)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	936	(1)	856	(1)	616	(1)
West Coast Region						
Average Sales Price per Mcf of Gas	$ 10.03		$ 6.34		$ 3.82	
Average Sales Price per Barrel of Oil	$ 94.06		$ 60.50		$ 45.94	
Average Sales Price per Mcf of Gas (after hedging)	$ 10.03		$ 6.34		$ 3.82	
Average Sales Price per Barrel of Oil (after hedging)	$ 70.53		$ 56.55		$ 56.97	
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 4.83		$ 3.74		$ 3.14	
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	39	(2)	41		44	
Total Company						
Average Sales Price per Mcf of Gas	$ 5.05		$ 2.49		$ 1.77	
Average Sales Price per Barrel of Oil	$ 94.10		$ 60.49		$ 45.94	
Average Sales Price per Mcf of Gas (after hedging)	$ 2.71		$ 2.25		$ 2.07	
Average Sales Price per Barrel of Oil (after hedging)	$ 70.80		$ 56.54		$ 56.96	
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.81		$ 0.82		$ 0.84	
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	966		897		660	

(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, 2022, 2021 and 2020) contributed 574 MMcfe, 597 MMcfe and 463 MMcfe of daily production in 2022, 2021 and 2020, respectively. The average lifting costs (per Mcfe) were $0.71 in 2022, $0.70 in 2021 and $0.70 in 2020. The Utica Shale fields (which exceed 15% of total reserves at September 30, 2022, 2021 and 2020) contributed 357 MMcfe, 255 MMcfe and 151 MMcfe of daily production in 2022, 2021 and 2020, respectively. The average lifting costs (per Mcfe) were $0.63 in 2022, $0.62 in 2021 and $0.62 in 2020.

(2) West Coast region properties were sold at June 30, 2022.

Productive Wells

At September 30, 2022	Appalachian Region		West Coast Region		Total Company	
	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	996	—	—	—	996	—
Productive Wells — Net	870	—	—	—	870	—

Developed and Undeveloped Acreage

At September 30, 2022	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
— Gross	655,433	—	655,433
— Net	643,381	—	643,381
Undeveloped Acreage			
— Gross	675,886	—	675,886
— Net	636,523	—	636,523
Total Developed and Undeveloped Acreage			
— Gross	1,331,319	—	1,331,319
— Net	1,279,904 (1)	—	1,279,904

(1) Of the 1,279,904 Total Developed and Undeveloped Net Acreage in the Appalachian region as of September 30, 2022, there are a total of 1,208,976 net acres in Pennsylvania. Of the 1,208,976 total net acres in Pennsylvania, shale development in the Marcellus, Utica or Geneseo shales has occurred on approximately 121,411 net acres, or 10% 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, 2022, the aggregate amounts of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 2,569 acres in 2023 (2,368 net acres), 15,203 acres in 2024 (14,310 net acres), 1,547 acres in 2025 (1,388 net acres) and 192,105 acres thereafter (187,765 net acres). The remaining 464,462 gross acres (430,692 net acres) represent non-expiring oil and gas rights owned by the Company. Of the acreage that is currently scheduled to expire in 2023, 2024 and 2025, Seneca has 80.2 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 2022	Productive 2021	Productive 2020	Dry 2022	Dry 2021	Dry 2020
United States						
Appalachian Region						
Net Wells Completed						
— Exploratory	—	—	—	—	—	1.00
— Development(1)	43.00	47.83	39.84	2.50	2.00	6.50
West Coast Region						
Net Wells Completed						
— Exploratory	—	—	—	—	—	—
— Development	23.00	10.00	34.00	—	—	—
Total Company						
Net Wells Completed						
— Exploratory	—	—	—	—	—	1.00
— Development	66.00	57.83	73.84	2.50	2.00	6.50

(1) Fiscal 2022, 2021 and 2020 Appalachian region dry wells include 2.5, 2 and 4.5 net wells, respectively, drilled prior to 2012 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 2022, 2021 and 2020 after the Company determined it would not continue development activities. The remaining 2 dry wells in fiscal 2020 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, 2022	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
— Gross	49.00	—	49.00
— Net	46.50	—	46.50

(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, 2022, there were 9,236 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, 2022, the Company issued a total of 6,560 unregistered shares of Company common stock to non-employee directors of the Company then serving on the Board of Directors of the Company (or, in the case of non-employee directors who elected to defer receipt of such shares pursuant to the Company's Deferred Compensation Plan for Directors and Officers (the "DCP"), to the DCP trustee), consisting of 656 shares per 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, 2022. The Company issued an additional 273 unregistered shares in the aggregate on July 15, 2022, pursuant to the dividend reinvestment feature of the DCP, to the six non-employee directors who defer the shares issued for the quarter ended September 30, 2022. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

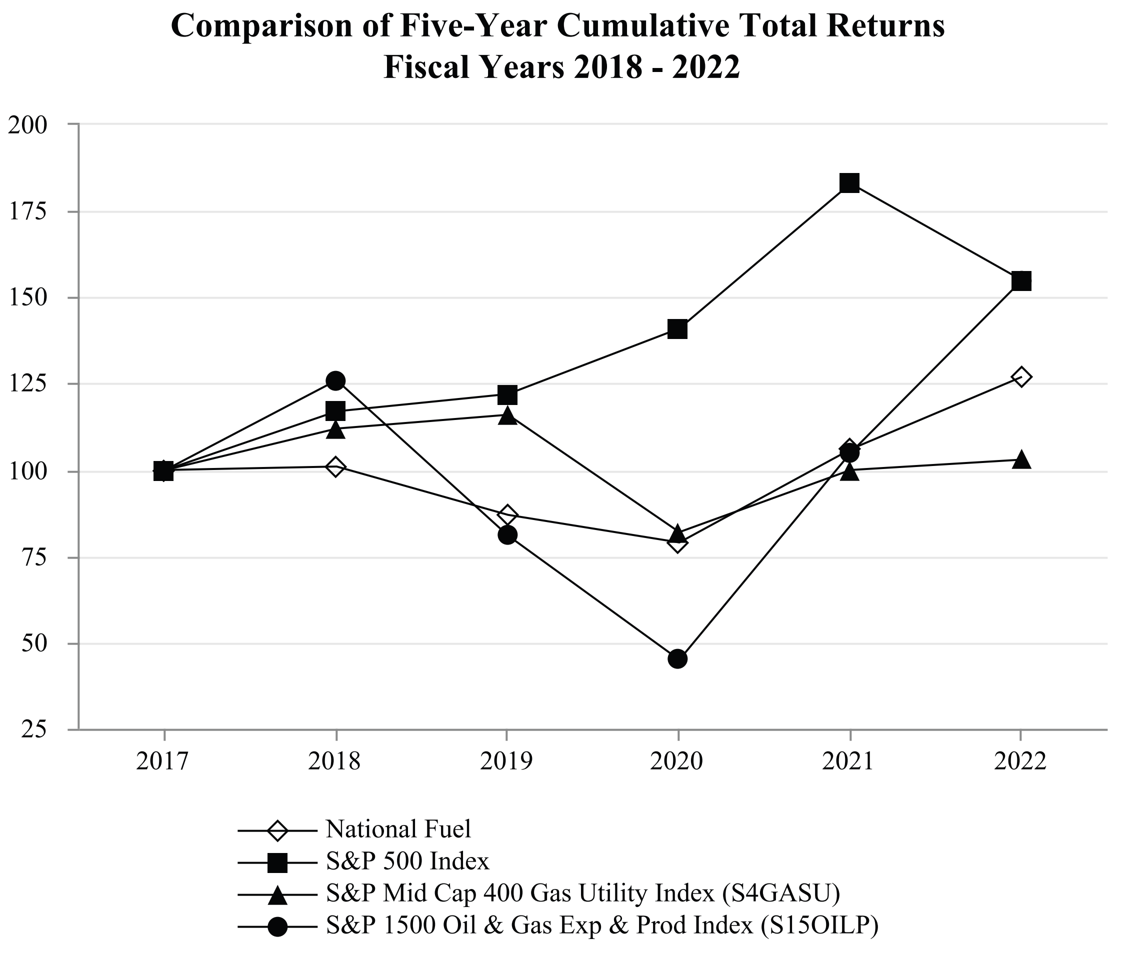
Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs(b)
July 1-31, 2022	12,420	$ 65.24	—	6,971,019
Aug. 1-31, 2022	10,598	$ 72.22	—	6,971,019
Sept. 1-30, 2022	9,387	$ 71.18	—	6,971,019
Total	32,405	$ 69.37	—	6,971,019

(a) Represents (i) shares of common stock of the Company purchased with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock-based compensation awards for the payment of applicable withholding taxes. During the quarter ended September 30, 2022, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 32,405 shares purchased other than through a publicly announced share repurchase program, 29,440 were purchased for the Company's 401(k) plans and 2,965 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 Company has not repurchased any shares since September 17, 2008. The repurchase program has no expiration date and management would discuss with the Company's Board of Directors any future repurchases under this program.

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, 2017 through September 30, 2022. The graph assumes that the value of the investment in the Company's common stock and in each index was $100 on September 30, 2017 and that all dividends were reinvested.



	2017	2018	2019	2020	2021	2022
National Fuel	$100	$101	$87	$79	$106	$127
S&P 500 Index	$100	$117	$122	$141	$183	$155
S&P Mid Cap 400 Gas Utility Index (S4GASU)	$100	$112	$116	$82	$100	$103
S&P 1500 Oil & Gas Exp & Prod Index (S15OILP)	$100	$126	$81	$45	$105	$155

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 ***(Reserved)***

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, storage and distribution of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current development activities are focused primarily in the Marcellus and Utica shales. The common geographic footprint of the Company's subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian basin to markets in the eastern United States and Canada. The Company's efforts in this regard are not limited to affiliated projects. The Company has also been designing and building pipeline projects for the transportation of natural gas for non-affiliated natural gas customers in the Appalachian basin. The Company 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. 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.

Part of the Board and management's strategic and capital spending decision process includes identifying and assessing climate-related risks and opportunities. Management reports quarterly to the Board on critical and potentially emerging risks, including climate-related risks, as part of the Enterprise Risk Management process. 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 physical and transitional climate risks, including policy and legal risks, technological developments, shifts in market conditions, including future natural gas usage, and reputational risks, and the impact of those risks on the Company's business. In March 2022, the Company published its inaugural Climate Report, analyzing climate-related transitional and physical risks, and describing our strategy for addressing those risks, as well as the resiliency of that strategy under a carbon constrained scenario. The Company reviews and considers adjustments to its approach to capital investment in response to these transitional developments, with its long-term, returns-focused approach.

The Company recognizes the important role of ongoing system modernization and efficiency in reducing greenhouse gas emissions and remains focused on reducing the Company's carbon footprint, with these efforts positioning natural gas, and the Company's related infrastructure, to remain an important part of the energy complex. In 2021, the Company set methane intensity reduction targets at each of its businesses, an absolute greenhouse gas emissions reduction target for the consolidated Company, and greenhouse gas reduction targets associated with the Company's utility delivery system. In 2022, the Company began measuring progress against these reduction targets. The Company also incorporated short-term and long-term executive compensation goals designed to incentivize and reward performance if reduction targets are met or exceeded. The Company's ability to estimate accurately the time, costs and resources necessary to meet these emissions reduction targets may change as environmental exposures and opportunities change, technology advances, and legislative and regulatory updates are issued.

Fiscal 2022 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” and;
4. Other Matters, including: (a) 2022 and projected 2023 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; (d) environmental matters; and (e) effects of inflation.

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 2022 and fiscal 2021. 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 2020 to fiscal 2021 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, 2021, filed with the SEC on November 19, 2021.

On June 30, 2022, the Company completed the sale of Seneca’s California assets to Sentinel Peak Resources California LLC for a total sale price of $253.5 million, consisting of $240.9 million in cash and contingent consideration valued at $12.6 million at closing. The Company pursued this sale given the strong commodity price environment and the Company's strategic focus in the Appalachian Basin. Under the terms of the purchase and sale agreement, the Company can receive up to three annual contingent payments between calendar year 2023 and calendar year 2025, not to exceed $10 million per year, with the amount of each annual payment calculated as $1.0 million for each $1 per barrel that the ICE Brent Average for each calendar year exceeds $95 per barrel up to $105 per barrel. The sale price, which reflected an effective date of April 1, 2022, was reduced for production revenues less expenses that were retained by Seneca from the effective date to the closing date. Under the full cost method of accounting for oil and natural gas properties, $220.7 million of the sale price at closing was accounted for as a reduction of capitalized costs since the disposition did not alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center. The remainder of the sale price ($32.8 million) was applied against assets that are not subject to the full cost method of accounting, with the Company recognizing a gain of $12.7 million on the sale of such assets. The majority of this gain related to the sale of emission allowances.

The Company has continued to pursue development projects to expand its Pipeline and Storage segment. One project on Supply Corporation's system, referred to as the FM100 Project, upgraded a 1950’s era pipeline in northwestern Pennsylvania and created 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 ("Transco") system at Leidy, Pennsylvania. Construction activities on the expansion portion of the FM100 Project are complete and the project was placed into service in December 2021. This project will provide incremental annual transportation revenues of approximately $50 million. The FM100 Project is discussed in more detail in the Capital Resources and Liquidity section that follows. For further discussion of the Pipeline and Storage segment's revenues and earnings, refer to the Results of Operations section below.

The Company's Exploration and Production segment continues to grow, as evidenced by an 8% growth in proved reserves from the prior year to a total of 4,172 Bcfe at September 30, 2022. Production increased 25.1 Bcfe during the fiscal year ended September 30, 2022 to a total of 352.5 Bcfe, and is expected to increase again in fiscal 2023. The December 2021 commencement of service for Seneca’s 330,000 Dth per day of incremental pipeline capacity on the Leidy South Project, which was the companion project of the Company's FM100 Project, contributed to the production growth in fiscal 2022. This incremental pipeline capacity provides Seneca with the ability to reach premium Transco Zone 6 (Non-New York) markets.

On February 28, 2022, the Company entered into a Credit Agreement (as amended from time to time, the "Credit Agreement") with a syndicate of twelve banks. The Credit Agreement replaced the previous Fourth Amended and Restated Credit Agreement and a previous 364-Day Credit Agreement. The Credit Agreement provides a $1.0 billion unsecured committed revolving credit facility with a maturity date of February 26, 2027.

On June 30, 2022, the Company entered into a new 364-Day Credit Agreement (the "364-Day Credit Agreement") with a syndicate of five banks, all of which are also lenders under the Credit Agreement. The 364-Day Credit Agreement provides an additional $250.0 million unsecured committed delayed draw term loan credit facility with a maturity date of June 29, 2023. The Company elected to draw $250.0 million under the facility on October 27, 2022. The Company is using the proceeds for general corporate purposes, which will include the redemption in November of a portion of the Company's outstanding long-term debt maturing in March 2023. The Company does not anticipate long-term refinancing for the $250.0 million drawn under the facility or the maturing long-term debt in March 2023.

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, gas and oil property acquisition, exploration and development costs are capitalized under the full cost method of accounting, with natural gas properties in the Appalachian region being the primary component of these capitalized costs after the June 30, 2022 sale of the Company's California oil and natural gas properties. That sale is discussed in more detail in Item 8 at Note B — Asset Acquisitions and Divestitures. 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 unproved 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 natural 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. At September 30, 2022, the ceiling exceeded the book value of the oil and gas properties by approximately $3.2 billion. The 12-month average of the first day of the month price for natural gas for each month during 2022, based on the quoted Henry Hub spot price for natural gas, was $6.13 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 Henry Hub price, which is only indicative of 12-month average prices for 2022. Actual realized pricing includes adjustments for regional market differentials, transportation fees and contractual arrangements.) In regard to the sensitivity of the ceiling test calculation to commodity price changes, if natural gas prices were $0.25 per MMBtu lower than the average prices used at September 30, 2022 in the ceiling test calculation, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $2.9 billion (after-tax), which would not have resulted in an impairment charge. This calculated amount is based solely on price changes and does not take into account any other changes to the ceiling test calculation, including, among others, changes in reserve quantities and future cost estimates.

It is difficult to predict what factors could lead to future impairments under the SEC's full cost ceiling test. As discussed above, fluctuations in or subtractions from proved reserves, increases in development costs for undeveloped reserves and significant fluctuations in natural gas prices have an impact on the amount of the ceiling at any point in time.

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.

RESULTS OF OPERATIONS

EARNINGS

2022 Compared with 2021

The Company's earnings were $566.0 million in 2022 compared with earnings of $363.6 million in 2021. The increase in earnings of $202.4 million was primarily a result of higher earnings in all reportable segments, slightly offset by losses in the Corporate and All Other categories. 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 2022 and 2021:

2022 Events

- The reversal of a deferred tax valuation allowance of $24.9 million recorded in the Exploration and Production and Gathering segments.
- A $28.4 million remeasurement of accumulated deferred income taxes, primarily in the Exploration and Production and Gathering segments, related to a reduction in the Pennsylvania state corporate income tax rate that was signed into law in July 2022.
- A gain recognized on the sale of Seneca's California assets of $12.7 million ($9.5 million after-tax) recorded during 2022 in the Exploration and Production segment related to a portion of the sale price that was applied to assets that were not subject to the full cost method of accounting.
- A loss of $44.6 million ($33.3 million after-tax) recorded during 2022 in the Exploration and Production segment related to the termination of this segment's remaining crude oil derivative contracts as a result of the sale of Seneca's California assets.
- Transaction and severance costs of $9.7 million ($7.2 million after-tax) incurred during 2022 in the Exploration and Production segment related to the sale of Seneca's California assets.
- The reduction of an OPEB regulatory liability that increased earnings by $18.5 million ($14.6 million after-tax) recorded during 2022 in the Utility segment in accordance with a regulatory proceeding in Distribution Corporation's Pennsylvania service territory.

2021 Events

- Non-cash impairment charges of $76.2 million ($55.2 million after-tax) recorded during 2021 for the Exploration and Production segment's oil and gas producing properties.
- A gain recognized on the sale of timber properties of $51.1 million ($37.0 million after-tax) recorded during 2021 in the Company's All Other category.
- A loss of $15.7 million ($11.4. million after-tax) recorded in the Exploration and Production and Gathering segments during 2021 for the premium paid on early redemption of long-term debt.

Earnings (Loss) by Segment

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Exploration and Production	$ 306,064	$ 101,916	$ (326,904)
Pipeline and Storage	102,557	92,542	78,860
Gathering	101,111	80,274	68,631
Utility	68,948	54,335	57,366
Total Reported Segments	578,680	329,067	(122,047)
All Other	(9)	37,645	(269)
Corporate	(12,650)	(3,065)	(1,456)
Total Consolidated	$ 566,021	$ 363,647	$ (123,772)

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30	
	2022	2021
	(Thousands)	
Gas (after Hedging)	$ 930,130	$ 705,326
Oil (after Hedging)(1)	113,588	126,369
Gas Processing Plant	3,511	2,960
Other	(36,765)	2,042
Operating Revenues	$ 1,010,464	$ 836,697

Production

	Year Ended September 30	
	2022	2021
Gas Production *(MMcf)*		
Appalachia	341,700	312,300
West Coast	1,211	1,720
Total Production	342,911	314,020
Oil Production *(Mbbl)*		
Appalachia	16	2
West Coast	1,588	2,233
Total Production	1,604	2,235

Average Prices

	Year Ended September 30	
	2022	2021
Average Gas Price/Mcf		
Appalachia	$ 5.03	$ 2.46
West Coast	$ 10.03	$ 6.34
Weighted Average	$ 5.05	$ 2.49
Weighted Average After Hedging(2)	$ 2.71	$ 2.25
Average Oil Price/Barrel (Bbl)		
Appalachia	$ 97.82	$ 48.02
West Coast	$ 94.06	$ 60.50
Weighted Average	$ 94.10	$ 60.49
Weighted Average After Hedging(1)(2)	$ 70.80	$ 56.54

(1) Oil revenue and weighted average oil price after hedging for the year ended September 30, 2022 excludes a loss on discontinuance of crude oil cash flow hedges of $44.6 million. This loss is presented in other revenue in the table above.

(2) 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.

2022 Compared with 2021

Operating revenues for the Exploration and Production segment increased $173.8 million in 2022 as compared with 2021. Gas production revenue after hedging increased $224.8 million primarily due to a $0.46 per Mcf increase in the weighted average price of gas after hedging coupled with a 28.9 Bcf increase in gas production. The increase in gas production was largely due to new Marcellus and Utica wells in the Appalachian region. Oil production revenue after hedging decreased $12.8 million primarily due to a 631 Mbbl decrease in crude oil production, partially offset by a $14.26 per Bbl increase in the weighted average price of oil after hedging. The decrease in oil production is mainly attributed to the sale of California assets at June 30, 2022. In addition, other revenue decreased $38.8 million and plant revenue increased $0.6 million. The decrease in other revenue was primarily attributed to a loss on the discontinuance of crude oil cash flow hedges related to the sale of California assets combined with royalty shut-in payments made in accordance with lease agreements. These were partially offset by a temporary capacity release of Leidy South and TC Pipeline transportation contracts. Finally, other revenue also increased from Highland Field Services water treatment plants acquired at the end of fiscal 2021.

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

2022 Compared with 2021

The Exploration and Production segment's earnings for 2022 were $306.1 million, an increase of $204.2 million when compared with earnings of $101.9 million for 2021. The increase in earnings was primarily attributable to higher natural gas prices after hedging ($126.3 million), higher natural gas production ($51.3 million), and higher oil prices after hedging ($18.1 million). Additionally, a $55.2 million impairment was recorded during 2021 that did not recur during 2022. Certain deferred tax adjustments during 2022 also contributed to the earnings increase. The Exploration and Production segment reversed a valuation allowance ($28.6 million) on deferred tax assets related to certain state net operating loss and credit carryforwards as these deferred tax assets are now expected to be realized in the future. The Exploration and Production segment also recorded an income tax benefit ($16.2 million) from the remeasurement of deferred income taxes related to a state corporate income tax rate reduction in Pennsylvania that was signed into law in July 2022. The law reduces the Pennsylvania corporate income tax rate to 8.99% for fiscal 2024, and starting with fiscal 2025, the rate is further reduced by 0.5% annually until it reaches 4.99% for fiscal 2032.

In addition to the factors discussed above, the Exploration and Production segment's earnings were also impacted by the following factors. Factors that increased earnings included a 2022 gain ($9.5 million) that was recognized on the sale of the Exploration and Production segment's California non-full cost pool assets as well as a 2021 loss ($10.7 million) recognized for this segment's share of the premium paid by the Company to redeem $500 million of the Company's 4.90% notes that were scheduled to mature in December 2021. Factors that reduced earnings included a loss related to the discontinuance of this segment's crude oil cash flow hedges ($33.3 million), which was driven by the sale of the California assets, lower crude oil production ($28.2 million), higher lease operating and transportation expenses ($13.1 million), higher depletion expense ($20.3 million), higher other operating expenses ($5.4 million), an unrealized loss on a derivative asset ($3.2 million), higher other taxes ($2.5 million) and a higher effective tax rate ($6.3 million). The Company also recorded transaction and severance costs ($7.2 million) during 2022 associated with the sale of the California assets. The increase in lease operating and transportation expenses was primarily due to increased gathering and transportation costs in the Appalachian region offset by lower costs in the West Coast region due to selling the assets on June 30, 2022. The increase in depletion expense was primarily due to the increase in production, combined with a $0.03 per Mcfe increase in the depletion rate. The increase in other operating expenses was primarily attributed to abandonment costs related to certain offshore Gulf of Mexico wells formally owned by the Company. In addition, the increase in other operating expenses was attributed to operating costs associated with the Highland Field Services water treatment plants acquired at the end of fiscal 2021. The unrealized loss on a derivative asset represents an adjustment to the contingent consideration received for the sale of the California assets. The increase in other taxes was mainly attributed to increased Impact Fees in the Appalachian region as a result of an increase in natural gas prices. The Impact Fees are calculated annually based on calendar year NYMEX natural gas prices. The increase in the effective tax rate was primarily driven by a reduction to the valuation allowance recorded in fiscal 2021.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30	
	2022	2021
	(Thousands)	
Firm Transportation	$ 287,486	$ 254,853
Interruptible Transportation	2,481	996
	289,967	255,849
Firm Storage Service	84,565	83,032
Interruptible Storage Service	—	48
	84,565	83,080
Other	2,512	4,628
	$ 377,044	$ 343,557

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30	
	2022	2021
Firm Transportation	790,417	770,284
Interruptible Transportation	5,612	1,460
	796,029	771,744

2022 Compared with 2021

Operating revenues for the Pipeline and Storage segment increased $33.5 million in 2022 as compared with 2021. The increase in operating revenues was primarily due to an increase in transportation revenues of $34.1 million and an increase in storage revenues of $1.5 million, partially offset by a decrease in other revenue of $2.1 million. The increase in transportation revenues was primarily attributable to new demand charges for transportation service from Supply Corporation's FM100 Project, which was placed into service in December 2021. The increase from the FM100 Project includes the impact of a negotiated revenue step-up to Period 2 Rates that went into effect April 1, 2022, as specified in Supply Corporation's 2020 rate case settlement. This increase was partially offset by a decline in revenues associated with miscellaneous contract terminations and revisions. The increase in storage revenues was partially due to the Period 2 Rates that went into effect April 1, 2022 related to the FM100 Project, as discussed above. In addition, the Pipeline Safety and Greenhouse Gas Regulatory Costs (PS/GHG Regulatory Costs) surcharge that went into effect in November 2020 associated with Supply Corporation's 2020 rate case settlement also contributed to the increase in both transportation and storage revenues. The decrease in other revenue primarily reflects the non-recurrence of revenue associated with a contract buyout that occurred during the quarter ended December 31, 2020, combined with lower electric surcharge true-up revenues, partially offset by higher cashout revenues. Revenues collected through the electric surcharge mechanism are completely offset by electric power costs recorded in operation and maintenance expense. Cashout revenues are completely offset by purchased gas expense.

Transportation volume increased by 24.3 Bcf in 2022 as compared with 2021, primarily due to incremental volume from the FM100 Project, which was brought online in December 2021, as well as an increase in short-term contracts. These were partially offset by lower capacity utilization with certain contract shippers. Volume fluctuations, other than those caused by the addition or termination of contracts, generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

The 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). The amount of firm transportation capacity contracted on the Pipeline and Storage segment's facilities is expected to decrease in fiscal 2023, primarily due to the termination of two long-term contracts with a nonaffiliated party totaling 300 MDth per day. Lower contracted quantities at the time of a future rate proceeding would be taken into account and would be the basis for setting new rates. The timing of Supply Corporation's next rate filing is discussed below under Rate Matters.

Earnings

2022 Compared with 2021

The Pipeline and Storage segment's earnings in 2022 were $102.6 million, an increase of $10.1 million when compared with earnings of $92.5 million in 2021. The increase in earnings was primarily due to the impact of higher operating revenues of $26.5 million, as discussed above, which was partially offset by an increase in depreciation expense ($4.2 million), higher property taxes ($0.8 million), an increase in operating expenses ($7.6 million) and higher income tax expense ($2.3 million). The increase in depreciation expense was primarily due to incremental depreciation from the FM100 Project going into service in December 2021. The increase in property taxes was primarily due to the first-time assessment of property taxes for the Empire North project's Farmington compressor station. The increase in operating expenses was primarily due to a decrease in the reserve for preliminary project costs recorded during fiscal 2021 that did not recur in fiscal 2022, as well as an increase in personnel and technology-related costs and higher vehicle fuel costs. This was partially offset by lower power costs related to Empire's electric motor drive compressor station. The Pipeline and Storage segment also experienced higher purchased gas costs ($0.7 million), largely related to Empire's natural gas-driven compressor stations. The electric power costs and purchased gas costs are offset by an equal amount of revenue, as discussed above. The increase in income tax expense was mainly due to a reduction in benefits associated with the tax sharing agreement with affiliated companies combined with higher state income tax expense due to higher pre-tax earnings for fiscal 2022.

GATHERING

Revenues

Gathering Operating Revenues

	Year Ended September 30	
	2022	2021
	(Thousands)	
Gathering	$ 214,843	$ 193,264

Gathering Volume — (MMcf)

	Year Ended September 30	
	2022	2021
Gathered Volume	419,332	366,033

2022 Compared with 2021

Operating revenues for the Gathering segment increased $21.6 million in 2022 as compared with 2021, which was driven primarily by a 53.3 Bcf increase in gathered volume. The increase in gathered volume can be attributed primarily to an increase in natural gas production on the Covington, Wellsboro, Clermont and Trout Run gathering systems, which recorded increases of 17.9 Bcf, 11.7 Bcf, 10.1 Bcf and 13.6 Bcf, respectively. The increase in gathered volume can be attributed to the increase in gross natural gas production in the Appalachian region by producers connected to the aforementioned gathering systems.

Earnings

2022 Compared with 2021

The Gathering segment's earnings in 2022 were $101.1 million, an increase of $20.8 million when compared with earnings of $80.3 million in 2021. The increase in earnings was primarily attributable to higher gathering revenues ($17.0 million) driven by the increase in gathered volume (discussed above). Additionally, the Gathering segment recorded an income tax benefit ($11.9 million) from the remeasurement of deferred income taxes related to a state corporate income tax rate reduction in Pennsylvania that was signed into law in July 2022 (as discussed above, in the Exploration and Production segment). Earnings also increased as a result of the Gathering segment's recognition of a loss during the quarter end March 31, 2021 ($0.7 million) for its share of the premium paid by the Company to redeem $500 million of the Company's 4.90% notes that were scheduled to mature in December 2021. However, the Gathering segment's earnings were negatively impacted by the recording of deferred income tax expense ($3.7 million) as an offset to the reversal of the valuation allowance recorded by the Exploration and Production segment during the quarter ended September 30, 2022. This offset is a result of the Gathering and Exploration and Production segments' subsidiaries filing a combined state tax return. Earnings also decreased due to higher operating expenses ($3.2 million), higher depreciation expense ($1.3 million) and higher income tax expense ($0.6 million). The increase in operating expenses was largely due to higher costs for labor, major overhaul maintenance of compressor units at Trout Run gathering system compressor stations during fiscal 2022 and higher costs for material used to operate the compressor stations at the Trout Run, Covington and Clermont gathering systems. The increase in depreciation expense was largely due to higher plant balances associated with the Clermont and Covington gathering systems. The increase in income tax expense was primarily driven by a higher effective state income tax rate.

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30 2022	2021
	(Thousands)	
Retail Revenues:		
Residential	$ 691,034	$ 497,244
Commercial	95,120	63,954
Industrial	4,913	3,089
	791,067	564,287
Transportation	111,072	108,213
Other	(3,918)	(5,249)
	$ 898,221	$ 667,251

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30 2022	2021
Retail Sales:		
Residential	64,011	61,038
Commercial	9,621	8,741
Industrial	541	475
	74,173	70,254
Transportation	65,993	66,012
	140,166	136,266

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal(1)	Prior Year(1)
2022	Buffalo, NY	6,617	5,769	(12.8)%	0.7 %
	Erie, PA	6,147	5,368	(12.7)%	2.8 %
2021	Buffalo, NY	6,617	5,731	(13.4)%	(6.1)%
	Erie, PA	6,147	5,221	(15.1)%	(4.2)%

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

2022 Compared with 2021

Operating revenues for the Utility segment increased $231.0 million in 2022 compared with 2021. The increase resulted from a $226.8 million increase in retail gas sales revenues, which was primarily due to a significant increase in the cost of gas sold (per Mcf). In addition, there was a $2.9 million increase in transportation revenues and a $1.3 million increase in other revenues. The increase in transportation revenues, despite a small decrease in throughput, was largely due to an increase in marketer sales cashouts and an increase in the system modernization tracker allocation to transportation customers, which was partially offset by the migration of residential transportation customers previously served by marketers to retail service provided by the Utility segment. The increase in other revenues was primarily due to higher capacity release revenues and higher late payment charges billed to customers.

Purchased Gas

The cost of purchased gas is one of the Company's largest operating expenses. 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 $498.0 million and $274.8 million of Purchased Gas expense during 2022 and 2021, 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 ten 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 two local distribution companies 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

2022 Compared with 2021

The Utility segment's earnings in 2022 were $68.9 million, an increase of $14.6 million when compared with earnings of $54.3 million in 2021. The increase was primarily attributable to the conclusion of a regulatory proceeding by the PaPUC in February 2022, which resulted in the reduction of an OPEB-related regulatory liability that increased earnings ($14.6 million). While the regulatory proceeding reduced base rates in Pennsylvania by $5.6 million, this impact was more than offset by a decrease in non-service post-retirement benefit costs ($11.5 million) as Distribution Corporation's Pennsylvania service territory recognized OPEB income during fiscal 2022, compared to the prior year when it recognized OPEB expenses to match against the OPEB amounts collected in base rates. Additional details related to the regulatory proceeding are discussed in Note F — Regulatory Matters.

Other factors contributing to the increase in earnings included the positive earnings impact of a system modernization tracker in New York ($3.6 million), which is a rate mechanism that provides recovery of qualified leak prone pipe replacement costs, higher usage and the impact of weather on customer margins ($2.9 million), and a decrease in income tax expense ($0.6 million). These increases were partially offset by higher operating expenses ($9.5 million), which were primarily the result of higher personnel costs, transportation fuel costs, and outside services partially offset by a decrease in the provision for uncollectible accounts. The decrease in the provision for uncollectible accounts reflects the recording of incremental expense in 2021 due to the potential for future customer non-payment as a result of the COVID-19 pandemic. In addition, earnings were negatively impacted by higher interest expense ($2.0 million), which was largely the result of a higher weighted average interest rate on intercompany short-term borrowings, and higher depreciation expense ($1.8 million), primarily due to higher plant balances.

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is largely 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 2022, the WNC contributed approximately $4.8 million to earnings, as the weather was warmer than normal. In 2021, the WNC contributed approximately $4.5 million to earnings, as the weather was warmer than normal.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of Seneca's Northeast Division and corporate operations. Seneca's Northeast Division previously marketed timber from its New York and Pennsylvania land holdings. On December 10, 2020, the Company completed the sale of substantially all timber properties. Please refer to Item 8 at Note B — Asset Acquisitions and Divestitures for further discussion of the sale of timber properties.

Earnings

2022 Compared with 2021

All Other and Corporate operations recorded a loss of $12.7 million in 2022, a decrease of $47.3 million when compared with earnings of $34.6 million in 2021. The decrease was primarily attributable to the non-recurrence of a $51.1 million gain ($37.0 million gain after-tax) on the sale of timber properties recorded by Seneca's Northeast Division in 2021. Changes in unrealized gains and losses on investments in equity securities also contributed to the decrease. In 2022, the Company recorded unrealized losses of $9.2 million, while in 2021, the Company recorded unrealized gains of $0.1 million.

OTHER INCOME (DEDUCTIONS)

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

Net other deductions on the Consolidated Statement of Income decreased $13.7 million in 2022 as compared to 2021. This change is primarily attributable to non-service pension and post-retirement benefit income of $3.6 million for 2022 compared to non-service pension and post-retirement benefit costs of $31.3 million for 2021. As discussed above in the Utility segment, this is largely related to the February 2022 conclusion of the regulatory proceeding in Distribution Corporation's Pennsylvania service territory that addressed Distribution Corporation's recovery of OPEB expenses. In addition, there was an increase in other interest income of $1.7 million. This was partially offset by changes in unrealized gains and losses on investments in equity securities. During 2022, the Company recorded pre-tax unrealized losses of $13.8 million. During 2021, the Company recorded pre-tax unrealized gains of $0.2 million. Other income (deductions) was also impacted by a decrease in the cash surrender value of life insurance policies of $1.9 million, as well as a decrease in allowance for funds used during construction (equity component) of $2.5 million primarily as a result of the FM100 Project being placed into service in December 2021. There was also a mark-to-market revaluation that decreased contingent consideration by $4.4 million from the sale of Seneca's California assets. For further discussion, refer to Note J — Financial Instruments.

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 decreased $21.0 million in 2022 as compared to 2021. The Company redeemed $500.0 million of 4.90% notes in March 2021 and paid an early redemption premium of $15.7 million that was recorded as interest expense on long-term debt. The remaining decrease is due largely to a lower weighted average interest rate on long-term debt, stemming from the Company's issuance of $500.0 million of 2.95% notes in February 2021, which replaced $500.0 million of 4.90% notes that were retired in March 2021.

Other interest expense increased $5.0 million in 2022 as compared to 2021. The increase was primarily due to higher average interest rates for 2022 combined with higher average short-term debt balances in 2022 compared to 2021.

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	
	2022	2021
	(Millions)	
Provided by Operating Activities	$ 812.5	$ 791.6
Capital Expenditures	(811.8)	(751.7)
Net Proceeds from Sale of Oil and Gas Producing Properties	254.4	—
Net Proceeds from Sale of Timber Properties	—	104.6
Sale of Fixed Income Mutual Fund Shares in Grantor Trust	30.0	—
Other Investing Activities	8.7	13.8
Reduction of Long-Term Debt	—	(515.7)
Change in Notes Payable to Banks and Commercial Paper	(98.5)	128.5
Net Proceeds from Issuance of Long-Term Debt	—	495.3
Net Repurchases of Common Stock	(9.6)	(3.7)
Dividends Paid on Common Stock	(168.1)	(163.1)
Net Increase in Cash, Cash Equivalents, and Restricted Cash	$ 17.6	$ 99.6

The Company expects to have adequate amounts of cash available to meet both its short-term and long-term cash requirements for at least the next twelve months and for the foreseeable future thereafter. During 2023, cash provided by operating activities is expected to increase over the amount of cash provided by operating activities during 2022 and will be used to fund the Company's capital expenditures. There are two long-term debt maturities in March 2023, totaling $549 million. The Company expects to repay those securities through the use of cash on hand at the date of maturity and short-term borrowings. Looking at 2023 and 2024, based on current commodity prices, cash provided by operating activities is expected to exceed capital expenditures in each of those years. This is expected to provide the Company with the option to consider additional growth investments, further reductions in short-term or long-term debt, and increasing the amount of cash flow returned to shareholders, either through increases to the Company's dividend or via repurchases of common stock. These cash flow projections do not reflect the impact of acquisitions or divestitures that may arise in the future.

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income, gains and losses associated with investing and financing activities, and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, deferred income taxes, the reduction of an other post-retirement regulatory liability 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 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.

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. Refer to Item 8 at Note L —

Commitments and Contingencies under the heading "Other" for additional discussion concerning these contractual commitments as well as the amounts of future gas purchase, transportation and storage contract commitments expected to be incurred during the next five years and thereafter. Also refer to Item 8 at Note D — Leases for a discussion of the Company's operating lease arrangements and a schedule of lease payments during the next five years and thereafter.

Net cash provided by operating activities totaled $812.5 million in 2022, an increase of $20.9 million compared with the $791.6 million provided by operating activities in 2021. The increase in cash provided by operating activities primarily reflects higher cash provided by operating activities in the Exploration and Production segment and the Gathering segment, partially offset by lower cash provided by operating activities in the Utility segment. The increase in the Exploration and Production segment and the Gathering segment was primarily due to higher cash receipts from natural gas production and gathering services in the Appalachian region. The decrease in Utility segment is primarily due to lower rates in the Utility segment's Pennsylvania service territory that went into effect October 1, 2021 combined with the timing of gas cost recovery, timing of gas receivables and other regulatory true-ups. The rates that went into effect included a one-time customer bill credit of $25 million in October 2021 for previously overcollected OPEB expenses and the beginning of a 5-year pass back of an additional $29 million in previously overcollected OPEB expenses. Please refer to the Rate Matters section that follows for additional discussion of this matter.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets, including non-cash capital expenditures, totaled $829.4 million and $769.9 million in 2022 and 2021, respectively. The table below presents these expenditures:

	Year Ended September 30	
	2022	2021
	(Millions)	
Exploration and Production:		
Capital Expenditures	$ 565.8 (1)	$ 381.4 (2)
Pipeline and Storage:		
Capital Expenditures	95.8 (1)	252.3 (2)
Gathering:		
Capital Expenditures	55.5 (1)	34.7 (2)
Utility:		
Capital Expenditures	111.0 (1)	100.8 (2)
All Other and Corporate:		
Capital Expenditures	1.3	0.5
Eliminations	—	0.2
Total Expenditures	$ 829.4	$ 769.9

(1) 2022 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $83.0 million, $15.2 million, $10.7 million and $11.4 million, respectively, of non-cash capital expenditures.

(2) 2021 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $47.9 million, $39.4 million, $4.8 million and $10.6 million, respectively, of non-cash capital expenditures.

Exploration and Production

In 2022, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $547.1 million for the Appalachian region (including $161.4 million in the Marcellus Shale area and $370.6 million in the Utica Shale area) and $18.7 million for the West Coast region. These amounts included approximately $154.3 million spent to develop proved undeveloped reserves.

In 2021, the majority of the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $368.1 million for the Appalachian region (including $117.2 million in the Marcellus Shale area and $213.8 million in the Utica Shale area) and $13.3 million for the West Coast region. These amounts included approximately $81.2 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The Pipeline and Storage segment's capital expenditures for 2022 were primarily for additions, improvements and replacements to this segment's transmission and gas storage systems, which included system modernization expenditures that enhance the reliability and safety of the systems and reduce emissions. In addition, the Pipeline and Storage segment capital expenditures for 2022 include expenditures related to Supply Corporation's FM100 Project ($25.2 million). The FM100 Project upgraded a 1950's era pipeline in northwestern Pennsylvania and created 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. Supply Corporation and Transco executed a precedent agreement whereby Transco has leased this additional capacity as part of a Transco expansion project ("Leidy South"), creating incremental transportation capacity to Transco Zone 6 (Non-New York) 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. Construction activities on the expansion portion of the FM100 Project are complete and the project commenced partial in-service on December 1, 2021, with full in-service on December 19, 2021. Abandonment activities on the project continue in calendar year 2022. As of September 30, 2022, approximately $211.3 million has been spent on the FM100 Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2022.

The Pipeline and Storage segment's capital expenditures for 2021 were primarily for expenditures related to Supply Corporation's FM100 Project ($179.0 million). In addition, the Pipeline and Storage segment capital expenditures for 2021 included additions, improvements and replacements to this segment's transmission and gas storage systems.

Gathering

The majority of the Gathering segment's capital expenditures for 2022 included expenditures related to the continued expansion of Midstream Company's Clermont, Covington, Trout Run and Wellsboro gathering systems, as discussed below. Midstream Company spent $20.9 million, $27.0 million, $4.9 million and $2.3 million in 2022 on the development of the Clermont, Covington, Trout Run and Wellsboro gathering systems, respectively. These expenditures were largely attributable to the installation of new in-field gathering pipelines in the Clermont gathering system, as well as the continued expansion of centralized station facilities, including increased compression horsepower at the Clermont, Trout Run, and Wellsboro gathering systems. In the Tioga gathering system, which is part of Midstream Covington, expenditures were largely attributable to the installation of in-field gathering pipelines and upgraded station facilities related to new development.

The majority of the Gathering segment's capital expenditures for 2021 included expenditures related to the continued expansion of Midstream Company's Clermont, Covington and Wellsboro gathering systems. Midstream Company spent $23.1 million, $4.4 million and $3.7 million in 2021 on the development of the Clermont, Covington and Wellsboro gathering systems, respectively. These expenditures were largely attributable to new Clermont gathering pipelines, a new tie-in between the legacy Covington gathering system and the midstream gathering assets acquired from SWEPI LP, a subsidiary of Royal Dutch Shell plc ("Shell"), which is now referred to as the Tioga gathering system, as well as the continued development of centralized station facilities, including increased compression horsepower at the Clermont and Wellsboro gathering systems and additional dehydration on the Clermont gathering system.

Utility

The majority of the Utility segment's capital expenditures for 2022 and 2021 were made for main and service line improvements and replacements that enhance the reliability and safety of the system and reduce emissions. Expenditures were also made for main extensions.

Other Investing Activities

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

In October 2021, the Company sold $30 million of fixed income mutual fund shares held in a grantor trust that was established for the benefit of Pennsylvania ratepayers. The proceeds were used in the Utility segment's Pennsylvania service territory to fund a one-time customer bill credit of $25 million in October 2021 for previously overcollected OPEB expenses and the first year installment of a 5-year pass back of an additional $29 million in previously overcollected OPEB expenses in accordance with new rates that went into effect on October 1, 2021. Please refer to the Rate Matters section that follows for additional discussion of this matter.

In March 2022, the Company completed the sale of certain oil and gas assets located in Tioga County, Pennsylvania, effective as of October 1, 2021. The Company received net proceeds of $13.5 million from this sale. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

On June 30, 2022, the Company completed the sale of Seneca's California assets to Sentinel Peak Resources California LLC for a total sale price of $253.5 million, consisting of $240.9 million in cash and contingent consideration valued at $12.6 million at closing. The Company pursued this sale given the strong commodity price environment and the Company's strategic focus in the Appalachian Basin. Under the terms of the purchase and sale agreement, the Company can receive up to three annual contingent payments between calendar year 2023 and calendar year 2025, not to exceed $10 million per year, with the amount of each annual payment calculated as $1.0 million for each $1 per barrel that the ICE Brent Average for each calendar year exceeds $95 per barrel up to $105 per barrel. The sale price, which reflected an effective date of April 1, 2022, was reduced for production revenues less expenses that were retained by Seneca from the effective date to the closing date. Under the full cost method of accounting for oil and natural gas properties, $220.7 million of the sale price at closing was accounted for as a reduction of capitalized costs since the disposition did not alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center. The remainder of the sale price ($32.8 million) was applied against assets that are not subject to the full cost method of accounting, with the Company recognizing a gain of $12.7 million on the sale of such assets. The majority of this gain related to the sale of emission allowances.

Estimated Capital Expenditures

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

	Year Ended September 30 2023	2024	2025
		(Millions)	
Exploration and Production(1)	$ 550	$ 525	$ 515
Pipeline and Storage	120	105	90
Gathering	95	110	95
Utility(2)	120	135	135
All Other	—	—	—
	$ 885	$ 875	$ 835

(1) Includes estimated expenditures for the years ended September 30, 2023, 2024 and 2025 of approximately \$308 million, \$95 million and \$82 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.

(2) Includes estimated expenditures for the years ended September 30, 2023, 2024, and 2025 of approximately \$95 million, \$100 million and \$100 million, respectively, for system modernization and safety to enhance the reliability and safety of the system and reduce emissions.

Exploration and Production

Capital expenditures for the Exploration and Production segment in 2023 through 2025 are expected to be primarily well drilling and completion expenditures in the Appalachian region.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2023 through 2025 are expected to include: the replacement and modernization of transmission and storage facilities, the reconditioning of storage wells, improvements of compressor stations and emissions reduction initiatives.

In addition, due to the continuing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia, specifically in the Marcellus and Utica Shale producing areas, Supply Corporation and Empire have completed and continue to pursue expansion projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines and to on-system markets, and markets beyond the Supply Corporation and Empire pipeline systems. Capital expenditures in 2023 through 2025 include minimal capital expenditures related to system expansion and forecasted amounts will be adjusted in the future to incorporate any new projects that are expected to be developed by the Company.

Gathering

The majority of the Gathering segment capital expenditures in 2023 through 2025, included in the table above, are expected to be for construction and expansion of gathering systems, as discussed below. The Gathering segment primarily invests capital to support Seneca's drilling and completion activity in their long-term development plan. Seneca has been in the process of shifting a larger share of its activity from its Western Development Area to Tioga County, Pennsylvania. As a result, the Gathering segment is expecting to see near-term increases in capital expenditures as it constructs the necessary infrastructure to support Seneca's activity in the region.

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 16 compressor stations and backbone and in-field gathering pipelines. Estimated capital expenditures in 2023 through 2025 include anticipated expenditures in the range of \$150 million to \$180 million for continued expansion of the Tioga gathering system.

NFG Midstream Clermont, LLC, a wholly-owned subsidiary of Midstream Company, continues to develop an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The Clermont gathering system was initially placed in service in July 2014. The current system consists of three compressor stations and backbone and in-field gathering pipelines. The total cost estimate for the continued buildout will be dependent on the nature and timing of Seneca's long-term plans. Estimated capital expenditures in 2023 through 2025 include anticipated expenditures in the range of $50 million to $70 million for the continued expansion of the Clermont 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 2023 through 2025 include anticipated expenditures in the range of $50 million to $60 million for the continued expansion of the Wellsboro 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 2023 through 2025 include anticipated expenditures in the range of $15 million to $25 million for the continued expansion of the Trout Run gathering system.

Utility

Capital expenditures for the Utility segment in 2023 through 2025 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. Additionally, capital expenditures are expected to increase after 2023 largely due to the anticipated implementation of a Distribution System Improvement Charge (DSIC) mechanism in the Utility's Pennsylvania Division upon completion of the rate proceeding initiated on October 28, 2022.

Project Funding

Over the past two years, the Company has been financing capital expenditures with cash from operations, short-term and long-term debt, common stock, and proceeds from the sale of timber properties and the Company's California assets. During fiscal 2022, capital expenditures were funded with cash from operations, short-term debt and proceeds from the sale of the Company's California assets. The Company issued long-term debt and common stock in June 2020 to help finance the acquisition of upstream assets and midstream gathering assets from Shell. The financing of the asset acquisition from Shell was completed in December 2020 when the Company completed the sale of substantially all of its timber properties, through the completion of the Reverse 1031 Exchange discussed above. Going forward, the Company expects to use cash on hand, cash from operations and short-term borrowings to finance capital expenditures. The level of short-term borrowings will depend upon the amount of cash provided by operations, which, in turn, will likely be most impacted by the timing of gas cost recovery in the Utility segment. It will also depend on natural gas production, and the associated commodity price realizations, as well as the level of hedging collateral deposits in the Exploration and Production segment.

In the Exploration and Production segment, the Company has entered into contractual obligations to support its development activities and operations in Pennsylvania, including hydraulic fracturing and other well completion services, well tending services, well workover activities, tubing and casing purchases, production equipment purchases, water hauling services and contracts for drilling rig services. Refer to Item 8 at Note L — Commitments and Contingencies under the heading “Other” for the amounts of contractual obligations expected to be incurred during the next five years and thereafter to support the Company’s exploration and development activities. These amounts are largely a subset of the estimated capital expenditures for the Exploration and Production segment shown above.

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. Refer to Item 8 at Note L — Commitments and Contingencies under the heading “Other” for the amounts of contractual commitments expected to be incurred during the next five years and thereafter associated with the Company's pipeline, compressor and gathering system modernization and expansion projects. These amounts are a subset of the estimated capital expenditures for the Pipeline and Storage segment, Gathering segment and Utility segment that are shown above.

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 natural gas properties, quicker development of existing natural gas properties, natural gas storage and transmission facilities, natural gas gathering and compression facilities and the expansion of natural gas transmission line capacities, regulated utility assets and other opportunities as they may arise. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company's other business segments depends, to a large degree, upon market and regulatory conditions as well as legislative actions.

FINANCING CASH FLOW

Consolidated short-term debt decreased $98.5 million, to a total of $60.0 million, when comparing the balance sheet at September 30, 2022 to the balance sheet at September 30, 2021. The maximum amount of short-term debt outstanding during the year ended September 30, 2022 was $675.4 million. In addition to cash provided by operating activities, 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, 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. For example, elevated commodity prices relative to its existing portfolio of derivative financial instruments led to the Company posting margin of $91.7 million with a number of its derivative counterparties as of September 30, 2022. The maximum amount of margin posted during the year ended September 30, 2022 was $430.6 million. The Company's margin deposits are reflected on the balance sheet as a current asset titled Hedging Collateral Deposits. To meet these margin requirements and other near-term cash flow needs, the Company utilized short-term debt in the form of commercial paper and borrowings under its revolving credit facility. At September 30, 2022, the Company had outstanding short-term notes payable to banks of $60.0 million. The Company did not have any commercial paper outstanding at September 30, 2022.

On February 28, 2022, the Company entered into the Credit Agreement with a syndicate of twelve banks. The Credit Agreement replaced the previous Fourth Amended and Restated Credit Agreement and a previous 364-Day Credit Agreement. The Credit Agreement provides a $1.0 billion unsecured committed revolving credit facility with a maturity date of February 26, 2027.

On June 30, 2022, the Company entered into the 364-Day Credit Agreement with a syndicate of five banks, all of which are also lenders under the Credit Agreement. The 364-Day Credit Agreement provides an additional $250.0 million unsecured committed delayed draw term loan credit facility with a maturity date of June 29, 2023. The Company elected to draw $250.0 million under the facility on October 27, 2022. The Company is using the proceeds for general corporate purposes, which will include the redemption in November of a portion of the Company's outstanding long-term debt maturing in March 2023.

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 $400 million. Since July 1, 2018, the Company recorded non-cash, after-tax ceiling test impairments totaling $381.4 million. As a result, at September 30, 2022, $190.7 million was added back to the Company's total capitalization for purposes of the calculation under the Credit Agreement and 364-Day Credit Agreement. On May 3, 2022, the Company entered into Amendment No. 1 to the Credit Agreement with the same twelve banks under the initial Credit Agreement. The amendment further modified the definition of consolidated capitalization, for purposes of calculating the debt to capitalization ratio under the Credit Agreement, to exclude, beginning with the quarter ended June 30, 2022, all unrealized gains or losses on commodity-related derivative financial instruments and up to $10 million in unrealized gains or losses on other derivative financial instruments included in Accumulated Other Comprehensive Income (Loss) within Total Comprehensive Shareholders' Equity on the Company's consolidated balance sheet. Under the Credit Agreement, such unrealized losses will not negatively affect the calculation of the debt to capitalization ratio, and such unrealized gains will not positively affect the calculation. The 364-Day Credit Agreement includes the same debt to capitalization covenant and the same exclusions of unrealized gains or losses on derivative financial instruments as the Credit Agreement. At September 30, 2022, the Company's debt to capitalization ratio, as calculated under the Credit Agreement and 364-Day Credit Agreement, was .49. The constraints specified in the Credit Agreement and 364-Day Credit Agreement would have permitted an additional $2.56 billion in short-term and/or long-term debt to be outstanding at September 30, 2022 (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

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

The Credit Agreement and 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 364-Day Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity.

On February 24, 2021, the Company issued $500.0 million of 2.95% notes due March 1, 2031. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $495.3 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. Additionally, the interest rate payable on the notes will be subject to adjustment from time to time, with a maximum adjustment of 2.00%, such that the coupon will not exceed 4.95%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to a rating below investment grade. 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, including the redemption of $500.0 million of the Company's 4.90% notes on March 11, 2021 that were scheduled to mature in December 2021. The Company redeemed those notes for $515.7 million, plus accrued interest.

The Current Portion of Long-Term Debt at September 30, 2022 consists of $500.0 million of 3.75% notes and $49.0 million of 7.395% notes, that each mature in March 2023. The Company does not anticipate long-term refinancing for these maturities. None of the Company's long-term debt as of September 30, 2021 had a maturity date within the following twelve-month period. As of September 30, 2022, the future contractual obligations related to aggregate principal amounts of long-term debt, including interest expense, maturing during the next five years and thereafter are as follows: $654.1 million in 2023, $95.4 million in 2024, $589.4 million in 2025, $548.9 million in 2026, $340.4 million in 2027, and $863.5 million thereafter. Refer to Item 8 at 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. Principal payments of long-term debt are a component of cash used in financing activities while interest payments on long-term debt are a component of cash used in operating activities.

The Company's embedded cost of long-term debt was 4.48% at both September 30, 2022 and September 30, 2021. Refer to "Interest Rate Risk" in this Item for a more detailed breakdown of the Company's embedded cost of long-term debt.

Under the Company's existing indenture covenants at September 30, 2022, the Company would have been permitted to issue up to a maximum of approximately $2.0 billion in additional unsubordinated long-term indebtedness at then current market interest rates, in addition to being able to issue new indebtedness to replace existing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. It is possible, depending on amounts reported in various income statement and balance sheet line items, that the indenture covenants could, for a period of time, prevent the Company from issuing incremental unsubordinated long-term debt, or significantly limit the amount of such debt that could be issued. Losses incurred as a result of significant impairments of oil and gas properties have in the past resulted in such temporary restrictions. The indenture covenants would not preclude the Company from issuing new long-term debt to replace existing long-term debt, or from issuing additional short-term debt. Please refer to the Critical Accounting Estimates section above for a sensitivity analysis concerning commodity price changes and their impact on the ceiling test.

The Company's 1974 indenture pursuant to which $99.0 million (or 3.7%) of the Company's long-term debt (as of September 30, 2022) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

OTHER MATTERS

In addition to the 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.

Supply Corporation and Empire have developed a project which would move significant prospective Marcellus and Utica 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. The Company remains committed to the project and, on June 29, 2022, received an extension of time from FERC, until December 31, 2024, to construct 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 timing of receipt of necessary regulatory approvals. As of September 30, 2022, approximately $55.8 million has been spent on the Northern Access project, including $24.2 million that has been spent to study the project. The remaining $31.6

million spent on the project is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2022.

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 may continue making contributions to the Retirement Plan in the future. During 2022, the Company contributed \$20.4 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2023 will be in the range of zero to \$8.0 million. For further discussion of the Company's Retirement Plan, including actuarial assumptions, refer to Item 8 at Note K — Retirement Plan and Other Post-Retirement Benefits. As noted in that footnote, the Retirement Plan has been closed to new participants since 2003. In that regard, the average remaining service life of active participants in the Retirement Plan is approximately 6 years.

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 does not anticipate making contributions to the VEBA trusts and/or 401(h) accounts in the near term. However, this will be subject to future review. During 2022, 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 2022. The Company does not expect to make any contributions to its VEBA trusts in 2023. For further discussion of the Company's other post-retirement benefits, including actuarial assumptions, refer to Item 8 at Note K — Retirement Plan and Other Post-Retirement Benefits. As noted in that footnote, the other post-retirement benefits provided by the Company have been closed to new participants since 2003. In that regard, the average remaining service life of active participants is approximately 4 years for those eligible for other post-retirement benefits.

The Company has made certain 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.

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, 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, 2022 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 transactions that are related to the financial instruments.

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act required the CFTC, SEC and other regulatory agencies to promulgate rules and regulations implementing the legislation, and 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. Rules developed by the CFTC and other regulators 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. Additionally, given the enforcement authority granted to the CFTC on anti-market manipulation, anti-fraud and disruptive trading practices, it is difficult to predict how the evolving enforcement priorities of the CFTC will impact our business. Should the Company violate any laws or regulations applicable to our hedging activities, it could be subject to CFTC enforcement action and material penalties and sanctions. The Company continues to monitor these enforcement and other regulatory developments, but cannot predict the impact that evolving application of the Dodd-Frank Act may have on its operations.

The authoritative guidance for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2022, the Company determined that nonperformance risk associated with the price swap agreements, no cost collars and foreign currency contracts 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 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, 2022. At September 30, 2022, the Company had not entered into any natural gas price swap agreements extending beyond 2026.

Natural Gas Price Swap Agreements

	Expected Maturity Dates				
	2023	2024	2025	2026	Total
Notional Quantities (Equivalent Bcf)	112.8	65.7	26.8	2.0	207.3
Weighted Average Fixed Rate (per Mcf)	$ 2.88	$ 3.07	$ 3.16	$ 3.18	$ 2.98
Weighted Average Variable Rate (per Mcf)	$ 6.02	$ 4.86	$ 4.55	$ 4.32	$ 5.45

At September 30, 2022, the Company would have paid its respective counterparties an aggregate of approximately $512.3 million to terminate the natural gas price swap agreements outstanding at that date.

At September 30, 2021, the Company had natural gas price swap agreements covering 398.8 Bcf at a weighted average fixed rate of $2.84 per Mcf.

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, 2022, the Company had not entered into any natural gas no cost collars extending beyond 2027.

	Expected Maturity Dates					
	2023	2024	2025	2026	2027	Total
Natural Gas						
Notional Quantities (Equivalent Bcf)	68.3	57.5	42.7	41.5	3.5	213.5
Weighted Average Ceiling Price (per Mcf)	$ 3.75	$ 3.89	$ 4.79	$ 4.90	$ 4.90	$ 4.24
Weighted Average Floor Price (per Mcf)	$ 3.20	$ 3.30	$ 3.60	$ 3.63	$ 3.63	$ 3.40

At September 30, 2022, the Company would have had to pay an aggregate of approximately $270.5 million to terminate the natural gas no cost collars outstanding at that date.

At September 30, 2021, the Company had no cost collars agreements covering 20.9 Bcf at a weighted average ceiling price of $3.25 per Mcf and a weighted average floor price of $2.81 per Mcf.

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, 2022. At September 30, 2022, the Company had not entered into any foreign currency exchange contracts extending beyond 2030.

	Expected Maturity Dates						
	2023	2024	2025	2026	2027	Thereafter	Total
Notional Quantities (Canadian Dollar in millions)	$14.7	$12.9	$10.9	$ 3.1	$ 2.4	$ 5.4	$49.4
Weighted Average Fixed Rate ($Cdn/$US)	$1.29	$1.29	$1.28	$1.32	$1.33	$ 1.34	$1.29
Weighted Average Variable Rate ($Cdn/$US)	$1.34	$1.33	$1.32	$1.34	$1.34	$ 1.34	$1.33

At September 30, 2022, absent other positions with the same counterparties, the Company would have paid to its respective counterparties an aggregate of $1.9 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 $2.5 billion at September 30, 2022. 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						
	2023	2024	2025	2026	2027	Thereafter	Total
	(Dollars in millions)						
Long-Term Fixed Rate Debt	$ 549.0	$ —	$ 500.0	$ 500.0	$ 300.0	$ 800.0	$2,649.0
Weighted Average Interest Rate Paid	4.1%	—	5.4%	5.5%	4.0%	3.6%	4.5%

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." As noted below, the Pennsylvania division currently has 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 provided for a return on equity of 8.7%, and directed the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018. The order also authorized the Company to recover approximately $15 million annually for pension and other post-employment benefit ("OPEB") expenses from customers. Because the Company's future pension and OPEB costs were projected to be satisfied with existing funds held in reserve, in July, Distribution Corporation made a filing with the NYPSC to effectuate a pension and OPEB surcredit to customers to offset these amounts being collected in base rates effective October 1, 2022. On September 16, 2022, the NYPSC issued an order approving the filing. With the implementation of this surcredit, Distribution Corporation will no longer be funding the pension from its New York jurisdiction and it will not be funding its VEBA trusts in its New York jurisdiction.

On August 13, 2021, the NYPSC issued an order extending the date through which qualified pipeline replacement costs incurred by the Company can be recovered using the existing system modernization tracker for two years (until March 31, 2023). The extension is contingent on the Company not filing a base rate case that would result in new rates becoming effective prior to April 1, 2023.

Pennsylvania Jurisdiction

Distribution Corporation's current delivery rates in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007. On October 28, 2022, Distribution Corporation made a filing with the PaPUC seeking an increase in its annual base rate operating revenues of $28.1 million with a proposed effective date of December 27, 2022. The Company is also proposing, among other things, to implement a weather normalization adjustment mechanism and a new energy efficiency and conservation pilot program for residential customers. The filing will be suspended for seven months by operation of law unless directed otherwise by the PaPUC.

Effective October 1, 2021, pursuant to a tariff supplement filed with the PaPUC, Distribution Corporation reduced base rates by $7.7 million in order to stop collecting OPEB expenses from customers. It also began to refund to customers overcollected OPEB expenses in the amount of $50.0 million. Certain other matters in the tariff supplement were unresolved. These matters were resolved with the PaPUC's approval of an Administrative Law Judge's Recommended Decision on February 24, 2022. Concurrent with that decision, the Company discontinued regulatory accounting for OPEB expenses and recorded an $18.5 million adjustment during the quarter ended March 31, 2022 to reduce its regulatory liability for previously deferred OPEB income amounts through September 30, 2021 and to increase Other Income (Deductions) on the consolidated financial statements by a like amount. The Company also increased customer refunds of overcollected OPEB expenses from $50.0 million to 54.0 million. All refunds specified in the tariff supplement are being funded entirely by grantor trust assets held by the Company, most of which are included in a fixed income mutual fund that is a component of Other Investments on the Company's Consolidated Balance Sheet. With the elimination of OPEB expenses in base rates, Distribution Corporation is no longer funding the grantor trust or its VEBA trusts in its Pennsylvania jurisdiction.

Pipeline and Storage

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

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

ENVIRONMENTAL MATTERS

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory requirements. In 2021, the Company set methane intensity reduction targets at each of its businesses, an absolute greenhouse gas emissions reduction target for the consolidated Company, and greenhouse gas reduction targets associated with the Company's utility delivery system. In 2022, the Company began measuring progress against these reduction targets. The Company's ability to estimate accurately the time, costs and resources necessary to meet emissions targets may change as environmental exposures and opportunities change and regulatory updates are issued.

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. 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. For example, the Inflation Reduction Act of 2022 (IRA) legislation was signed into law on August 16, 2022. The IRA includes a methane charge that is expected to be applicable to the reported annual methane emissions of certain oil and gas facilities, above specified methane intensity thresholds, starting in calendar year 2024. This portion of the IRA is to be administered by the EPA and potential fees will begin with emissions reported for calendar year 2024. The EPA regulates greenhouse gas emissions pursuant to the Clean Air Act. The regulations implemented by the EPA impose more stringent leak detection and repair requirements, and further address reporting and control of methane and volatile organic compound emissions. The Company must continue to comply with all applicable regulations. Additionally, 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. Pennsylvania's Governor also entered the Commonwealth into a cap-and-trade program known as the Regional Greenhouse Gas Initiative, however, the Commonwealth's participation is currently stayed due to ongoing litigation. 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 New York State legislature passed the CLCPA that mandates reducing greenhouse gas emissions by 40% from 1990 levels by 2030, and by 85% from 1990 levels by 2050, with the remaining emission reduction achieved by controlled offsets. The CLCPA also requires electric generators to meet 70% of demand with renewable energy by 2030 and 100% with zero emissions generation by 2040. These climate change and greenhouse gas initiatives could impact the Company's customer base and assets depending on the promulgation of final regulations and on regulatory treatment afforded in the process. Thus far, the only regulations promulgated in connection with the CLCPA are greenhouse gas emissions limits established by the NYDEC in 6 NYCRR Part 496, effective December 30, 2020. The NYDEC has until January 1, 2024 to issue further rules and regulations implementing the statute. The above-enumerated initiatives could also increase the Company’s cost of environmental compliance by increasing reporting requirements, requiring retrofitting of existing equipment, requiring installation of new equipment, and/or requiring the purchase of emission allowances. They could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals. Changing market conditions and new regulatory requirements, as well as unanticipated or inconsistent application of existing laws and regulations by administrative agencies, make it difficult to predict a long-term business impact across twenty or more years.

EFFECTS OF INFLATION

The Company’s operations are sensitive to increases in the rate of inflation because of its operational and capital spending requirements in both its regulated and non-regulated businesses. For the regulated businesses, recovery of increasing costs from customers can be delayed by the regulatory process of a rate case filing. For the non-regulated businesses, prices received for services performed or products produced are determined by market factors that are not necessarily correlated to the underlying costs required to provide the service or product.

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

1. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;
2. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design, retained natural gas and system modernization), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;
3. The Company’s ability to estimate accurately the time and resources necessary to meet emissions targets;
4. Governmental/regulatory actions and/or market pressures to reduce or eliminate reliance on natural gas;
5. Changes in economic conditions, including inflationary pressures, supply chain issues, liquidity challenges, and global, national or regional recessions, and their effect on the demand for, and customers’ ability to pay for, the Company’s products and services;
6. Changes in the price of natural gas;
7. The creditworthiness or performance of the Company’s key suppliers, customers and counterparties;
8. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company’s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company’s credit ratings and changes in interest rates and other capital market conditions;
9. Impairments under the SEC’s full cost ceiling test for natural gas reserves;
10. Increased costs or delays or changes in plans with respect to Company projects or related projects of other companies, as well as difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;
11. The Company's ability to complete planned strategic transactions;
12. The Company's ability to successfully integrate acquired assets and achieve expected cost synergies;

13. Changes in price differentials between similar quantities of natural gas sold 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;
14. The impact of information technology disruptions, cybersecurity or data security breaches;
15. Factors affecting the Company's ability to successfully identify, drill for and produce economically viable natural gas reserves, including among others geology, lease availability and costs, 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;
16. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits;
17. Other changes in price differentials between similar quantities of natural gas having different quality, heating value, hydrocarbon mix or delivery date;
18. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
19. Negotiations with the collective bargaining units representing the Company's workforce, including potential work stoppages during negotiations;
20. Uncertainty of gas reserve estimates;
21. Significant differences between the Company's projected and actual production levels for natural gas;
22. Changes in demographic patterns and weather conditions (including those related to climate change);
23. Changes in the availability, price or accounting treatment of derivative financial instruments;
24. 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;
25. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war, as well as economic and operational disruptions due to third-party outages;
26. Significant differences between the Company's projected and actual capital expenditures and operating expenses; or
27. 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.

Forward-looking and other statements in this Annual Report on Form 10-K regarding methane and greenhouse gas reduction plans and goals are not an indication that these statements are necessarily material to investors or required to be disclosed in our filings with the SEC. In addition, historical, current and forward-looking statements regarding methane and greenhouse gas emissions may be based on standards for measuring progress that are still developing, internal controls and processes that continue to evolve and assumptions that are subject to change in the future.

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 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 — 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, 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, 2022, 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, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended September 30, 2022 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, 2022, 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 Natural Gas Reserves on Natural Gas Properties, Net

As described in Note A to the consolidated financial statements, the Exploration and Production segment includes capitalized costs relating to natural gas producing activities, net of depreciation, depletion, and amortization (DD&A) of $1.9 billion as of September 30, 2022. 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. As disclosed by management, in addition to DD&A under the units-of-production method, proved reserves are a major component in 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. There were no ceiling test impairment charges for the year ended September 30, 2022. As of September 30, 2022, the ceiling exceeded the book value of the natural gas properties by approximately $3.2 billion. Estimates of the Company's proved natural 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 natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including quantities of natural gas that are ultimately recovered, the timing of the recovery of natural 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 natural gas reserves on natural 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 natural 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 data, methods, and assumptions used by management and its specialists in developing the estimates of quantities of proved natural 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 natural gas reserves that are utilized in the DD&A expense and ceiling test calculations. These procedures also included, among others, evaluating the reasonableness of the significant assumptions used by management related to the quantities of natural 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 natural gas reserves. As a basis for using this work, the specialists' qualifications and objectivity were understood and the Company's relationship with the specialists assessed. The procedures performed also included evaluation of the methods and assumptions used by the specialists, tests of the data used by the specialists and an evaluation of the specialists' findings.

/s/ PRICEWATERHOUSECOOPERS LLP
Buffalo, New York
November 18, 2022

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		
	2022	2021	2020
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues:			
Utility and Energy Marketing Revenues	$ 897,916	$ 667,549	$ 728,336
Exploration and Production and Other Revenues	1,010,629	837,597	611,885
Pipeline and Storage and Gathering Revenues	277,501	237,513	206,070
	2,186,046	1,742,659	1,546,291
Operating Expenses:			
Purchased Gas	392,093	171,827	233,890
Operation and Maintenance:			
Utility and Energy Marketing	193,058	179,547	181,051
Exploration and Production and Other	191,572	173,041	148,856
Pipeline and Storage and Gathering	136,571	123,218	108,640
Property, Franchise and Other Taxes	101,182	94,713	88,400
Depreciation, Depletion and Amortization	369,790	335,303	306,158
Impairment of Oil and Gas Producing Properties	—	76,152	449,438
	1,384,266	1,153,801	1,516,433
Gain on Sale of Assets	12,736	51,066	—
Operating Income	814,516	639,924	29,858
Other Income (Expense):			
Other Income (Deductions)	(1,509)	(15,238)	(17,814)
Interest Expense on Long-Term Debt	(120,507)	(141,457)	(110,012)
Other Interest Expense	(9,850)	(4,900)	(7,065)
Income (Loss) Before Income Taxes	682,650	478,329	(105,033)
Income Tax Expense	116,629	114,682	18,739
Net Income (Loss) Available for Common Stock	566,021	363,647	(123,772)
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	1,191,175	991,630	1,272,601
	1,757,196	1,355,277	1,148,829
Dividends on Common Stock	(170,111)	(164,102)	(156,249)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	(950)
Balance at End of Year	$ 1,587,085	$ 1,191,175	$ 991,630
Earnings (Loss) Per Common Share:			
Basic:			
Net Income (Loss) Available for Common Stock	$ 6.19	$ 3.99	$ (1.41)
Diluted:			
Net Income (Loss) Available for Common Stock	$ 6.15	$ 3.97	$ (1.41)
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	91,410,625	91,130,941	87,968,895
Used in Diluted Calculation	92,107,066	91,684,583	87,968,895

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2022	2021	2020
	(Thousands of dollars)		
Net Income (Loss) Available for Common Stock	$ 566,021	$ 363,647	$ (123,772)
Other Comprehensive Income (Loss), Before Tax:			
Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	9,561	17,862	(19,214)
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	11,054	16,229	15,361
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(1,050,831)	(665,371)	9,862
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	882,581	83,711	(93,295)
Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	1,313
Other Post-Retirement Adjustment for Regulatory Proceeding	(7,351)	—	—
Other Comprehensive Income (Loss), Before Tax	(154,986)	(547,569)	(85,973)
Income Tax Expense (Benefit) Related to the Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	2,169	4,072	(4,357)
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	2,574	3,762	3,566
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(287,608)	(179,028)	2,578
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	241,559	22,465	(25,521)
Income Tax Benefit (Expense) on Cumulative Effect of Adoption of Authoritative Guidance for Hedging	—	—	363
Income Tax Expense (Benefit) Related to Other Post-Retirement Adjustment for Regulatory Proceeding	(1,544)	—	—
Income Taxes — Net	(42,850)	(148,729)	(23,371)
Other Comprehensive Income (Loss)	(112,136)	(398,840)	(62,602)
Comprehensive Income (Loss)	$ 453,885	$ (35,193)	$ (186,374)

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30	
	2022	2021
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$ 12,551,909	$ 13,103,639
Less — Accumulated Depreciation, Depletion and Amortization	5,985,432	6,719,356
	6,566,477	6,384,283
Current Assets		
Cash and Temporary Cash Investments	46,048	31,528
Hedging Collateral Deposits	91,670	88,610
Receivables — Net of Allowance for Uncollectible Accounts of $40,228 and $31,639, Respectively	361,626	205,294
Unbilled Revenue	30,075	17,000
Gas Stored Underground	32,364	33,669
Materials, Supplies and Emission Allowances	40,637	53,560
Unrecovered Purchased Gas Costs	99,342	33,128
Other Current Assets	59,369	59,660
	761,131	522,449
Other Assets		
Recoverable Future Taxes	106,247	121,992
Unamortized Debt Expense	8,884	10,589
Other Regulatory Assets	67,101	60,145
Deferred Charges	77,472	59,939
Other Investments	95,025	149,632
Goodwill	5,476	5,476
Prepaid Pension and Post-Retirement Benefit Costs	196,597	149,151
Fair Value of Derivative Financial Instruments	9,175	—
Other	2,677	1,169
	568,654	558,093
Total Assets	$ 7,896,262	$ 7,464,825
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value; Authorized - 200,000,000 Shares; Issued and Outstanding - 91,478,064 Shares and 91,181,549 Shares, Respectively	$ 91,478	$ 91,182
Paid In Capital	1,027,066	1,017,446
Earnings Reinvested in the Business	1,587,085	1,191,175
Accumulated Other Comprehensive Loss	(625,733)	(513,597)
Total Comprehensive Shareholders' Equity	2,079,896	1,786,206
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,083,409	2,628,687
Total Capitalization	4,163,305	4,414,893
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	60,000	158,500
Current Portion of Long-Term Debt	549,000	—
Accounts Payable	178,945	171,655
Amounts Payable to Customers	419	21
Dividends Payable	43,452	41,487
Interest Payable on Long-Term Debt	17,376	17,376
Customer Advances	26,108	17,223
Customer Security Deposits	24,283	19,292
Other Accruals and Current Liabilities	257,327	194,169
Fair Value of Derivative Financial Instruments	785,659	616,410
	1,942,569	1,236,133
Other Liabilities		
Deferred Income Taxes	698,229	660,420
Taxes Refundable to Customers	362,098	354,089
Cost of Removal Regulatory Liability	259,947	245,636
Other Regulatory Liabilities	188,803	200,643
Pension and Other Post-Retirement Liabilities	3,065	7,526
Asset Retirement Obligations	161,545	209,639
Other Liabilities	116,701	135,846
	1,790,388	1,813,799
Commitments and Contingencies (Note L)	—	—
Total Capitalization and Liabilities	$ 7,896,262	$ 7,464,825

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2022	2021	2020
	(Thousands of dollars)		
Operating Activities			
Net Income (Loss) Available for Common Stock	$ 566,021	$ 363,647	$ (123,772)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Gain on Sale of Assets	(12,736)	(51,066)	—
Impairment of Oil and Gas Producing Properties	—	76,152	449,438
Depreciation, Depletion and Amortization	369,790	335,303	306,158
Deferred Income Taxes	104,415	105,993	54,313
Premium Paid on Early Redemption of Debt	—	15,715	—
Stock-Based Compensation	19,506	17,065	14,931
Reduction of Other Post-Retirement Regulatory Liability	(18,533)	—	—
Other	31,983	10,896	6,527
Change in:			
Receivables and Unbilled Revenue	(168,769)	(61,413)	(2,578)
Gas Stored Underground and Materials, Supplies and Emission Allowances	3,109	(2,014)	(6,625)
Unrecovered Purchased Gas Costs	(66,214)	(33,128)	2,246
Other Current Assets	291	(11,972)	49,367
Accounts Payable	11,907	31,352	(4,657)
Amounts Payable to Customers	398	(10,767)	6,771
Customer Advances	8,885	1,904	2,275
Customer Security Deposits	4,991	2,093	989
Other Accruals and Current Liabilities	34,260	34,314	5,001
Other Assets	(58,924)	1,250	(24,203)
Other Liabilities	(17,859)	(33,771)	4,628
Net Cash Provided by Operating Activities	812,521	791,553	740,809
Investing Activities			
Capital Expenditures	(811,826)	(751,734)	(716,153)
Net Proceeds from Sale of Oil and Gas Producing Properties	254,439	—	—
Net Proceeds from Sale of Timber Properties	—	104,582	—
Sale of Fixed Income Mutual Fund Shares in Grantor Trust	30,000	—	—
Acquisition of Upstream Assets and Midstream Gathering Assets	—	—	(506,258)
Other	8,683	13,935	(1,205)
Net Cash Used in Investing Activities	(518,704)	(633,217)	(1,223,616)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	(98,500)	128,500	(25,200)
Net Proceeds from Issuance of Long-Term Debt	—	495,267	493,007
Reduction of Long-Term Debt	—	(515,715)	—
Net Proceeds from Issuance (Repurchase) of Common Stock	(9,590)	(3,702)	161,603
Dividends Paid on Common Stock	(168,147)	(163,089)	(153,322)
Net Cash Provided by (Used in) Financing Activities	(276,237)	(58,739)	476,088
Net Increase (Decrease) in Cash, Cash Equivalents, and Restricted Cash	17,580	99,597	(6,719)
Cash, Cash Equivalents and Restricted Cash At Beginning of Year	120,138	20,541	27,260
Cash, Cash Equivalents and Restricted Cash At End of Year	$ 137,718	$ 120,138	$ 20,541
Supplemental Disclosure of Cash Flow Information			
Cash Paid (Refunded) For:			
Interest	$ 124,312	$ 135,136	$ 103,479
Income Taxes	$ 16,680	$ 6,374	$ (82,876)
Non-Cash Investing Activities:			
Non-Cash Capital Expenditures	$ 120,262	$ 102,700	$ 87,328
Non-Cash Contingent Consideration for Asset Sale	$ 12,571	$ —	$ —

See 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, the majority of which is in the Utility segment, is determined based on historical experience, the age of customer accounts, other specific information about customer accounts, and the economic and regulatory environment. Account balances are charged off against the allowance approximately twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered.

Activity in the allowance for uncollectible accounts are as follows:

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Balance at Beginning of Year	$ 31,639	$ 22,810	$ 25,788
Additions Charged to Costs and Expenses	13,209	14,940	12,339
Add: Discounts on Purchased Receivables	1,314	1,168	1,353
Deduct: Net Accounts Receivable Written-Off	5,934	7,279	16,670
Balance at End of Year	$ 40,228	$ 31,639	$ 22,810

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.

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.

Property, Plant and Equipment

In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. The Company's capitalized costs relating to oil and gas producing activities, net of accumulated depreciation, depletion and amortization, were $1.9 billion at September 30, 2022 and 2021.

For further discussion of capitalized costs, refer to Note N — 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 unproved properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent non-cash impairment is required to be charged to earnings in that quarter. At September 30, 2022, the ceiling exceeded the book value of the oil and gas properties by approximately $3.2 billion. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2022, 2021 and 2020, estimated future net cash flows were decreased by $1.0 billion, decreased by $76.1 million and increased by $180.0 million, respectively.

The principal assets of the Utility, Pipeline and Storage and Gathering segments, consisting primarily of gas distribution pipelines, transmission pipelines, storage facilities, gathering lines and compressor stations, are recorded at historical cost. There were no indications of any impairments to property, plant and equipment in the Utility, Pipeline and Storage and Gathering segments at September 30, 2022.

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 $202.4 million, $177.1 million and $166.8 million for the years ended September 30, 2022, 2021 and 2020, respectively. 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:

	As of September 30	
	2022	2021
	(Thousands)	
Exploration and Production	$ 6,088,476	$ 6,827,122
Pipeline and Storage	2,747,948	2,467,891
Gathering	971,665	932,583
Utility	2,411,707	2,306,603
All Other and Corporate	13,712	13,585
	$ 12,233,508	$ 12,547,784

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2022	2021	2020
Exploration and Production, per Mcfe(1)	$ 0.59	$ 0.56	$ 0.71
Pipeline and Storage	2.7 %	2.6 %	2.4 %
Gathering	3.6 %	3.6 %	3.2 %
Utility	2.7 %	2.7 %	2.7 %
All Other and Corporate	1.4 %	3.4 %	3.6 %

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note N — Supplementary Information for Oil and Gas Producing Activities, depletion of oil and gas producing properties amounted to $0.57, $0.54 and $0.69 per Mcfe of production in 2022, 2021 and 2020, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2022 and 2021 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, 2022, 2021 and 2020, 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 natural gas 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 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 on the Consolidated Statements of Income. Reference is made to Note J — Financial Instruments for further discussion concerning cash flow hedges.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) and changes for the years ended September 30, 2022 and 2021, net of related tax effects, are as follows (amounts in parentheses indicate debits) (in thousands):

	Gains and Losses on Derivative Financial Instruments	Funded Status of the Pension and Other Post-Retirement Benefit Plans	Total
Year Ended September 30, 2022			
Balance at October 1, 2021	$ (449,962)	$ (63,635)	$ (513,597)
Other Comprehensive Gains and Losses Before Reclassifications	(763,223)	7,392	(755,831)
Amounts Reclassified From Other Comprehensive Income (Loss)	641,022	8,480	649,502
Other Post-Retirement Adjustment for Regulatory Proceeding	—	(5,807)	(5,807)
Balance at September 30, 2022	$ (572,163)	$ (53,570)	$ (625,733)
Year Ended September 30, 2021			
Balance at October 1, 2020	$ (24,865)	$ (89,892)	$ (114,757)
Other Comprehensive Gains and Losses Before Reclassifications	(486,343)	13,790	(472,553)
Amounts Reclassified From Other Comprehensive Income (Loss)	61,246	12,467	73,713
Balance at September 30, 2021	$ (449,962)	$ (63,635)	$ (513,597)

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 $0.4 million and $0.7 million at September 30, 2022 and 2021, respectively. The total amount for accumulated losses was $53.2 million and $62.9 million at September 30, 2022 and 2021, respectively.

During the quarter ended March 31, 2022, the PaPUC concluded a regulatory proceeding that addressed the recovery of OPEB expenses in Distribution Corporation's Pennsylvania service territory. As a result of that proceeding, Distribution Corporation discontinued regulatory accounting for OPEB expenses in Pennsylvania and a regulatory deferral of $7.4 million ($5.8 million after tax) related to the funded status of Distribution Corporation’s other post-retirement benefit plans in Pennsylvania was reclassified to accumulated other comprehensive loss. For further discussion of this regulatory proceeding, refer to Note F — Regulatory Matters under the heading “Pennsylvania Jurisdiction.”

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, 2022 and 2021 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
	2022	2021	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	($882,594)	($83,973)	Operating Revenues
Foreign Currency Contracts	13	262	Operating Revenues
Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans:			
Prior Service Cost	(103)	(208)	(1)
Net Actuarial Loss	(10,951)	(16,021)	(1)
	(893,635)	(99,940)	Total Before Income Tax
	244,133	26,227	Income Tax Expense
	($649,502)	($73,713)	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 $32.4 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 2022, including transportation costs, the current cost of replacing this inventory of gas stored underground exceeded the amount stated on a LIFO basis by approximately $178.5 million at September 30, 2022.

Materials, Supplies and Emission Allowances

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

	Year Ended September 30	
	2022	2021
	(Thousands)	
Materials and Supplies — at average cost	$ 40,637	$ 34,880
Emission Allowances	—	18,680
	$ 40,637	$ 53,560

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, 2022, the remaining weighted average amortization period for such costs was approximately 5 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			
	2022	2021	2020	2019
Cash and Temporary Cash Investments	$ 46,048	$ 31,528	$ 20,541	$ 20,428
Hedging Collateral Deposits	91,670	88,610	—	6,832
Cash, Cash Equivalents, and Restricted Cash	$137,718	$120,138	$ 20,541	$ 27,260

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 derivative financial instruments in an unrealized loss position. 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.

Other Current Assets

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

	Year Ended September 30	
	2022	2021
	(Thousands)	
Prepayments	$ 17,757	$ 14,164
Prepaid Property and Other Taxes	14,321	14,788
State Income Taxes Receivable	5,933	1,502
Regulatory Assets	21,358	29,206
	$ 59,369	$ 59,660

Other Accruals and Current Liabilities

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

	Year Ended September 30	
	2022	2021
	(Thousands)	
Accrued Capital Expenditures	$ 64,720	$ 42,541
Regulatory Liabilities	31,293	60,860
Liability for Royalty and Working Interests	86,206	31,483
Non-Qualified Benefit Plan Liability	17,474	15,408
Other	57,634	43,877
	$ 257,327	$ 194,169

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, 2022 and 2021, customers in the balanced billing programs had advanced excess funds of $26.1 million and $17.2 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, 2022 and 2021, the Company had received customer security deposits amounting to $24.3 million and $19.3 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. For the years ended September 30, 2022 and September 30, 2021, the diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. SARs, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 2,858 securities excluded as being antidilutive for the year ended September 30, 2022 and 320,222 securities excluded as being antidilutive for the year ended September 30, 2021. As the Company recognized a net loss for the year ended September 30, 2020, the aforementioned potentially dilutive securities, amounting to 411,890 securities, were not recognized in the diluted earnings per share calculation for 2020.

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 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 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. For all Company stock awards, forfeitures are recognized as they occur.

Restricted stock units 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 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 and greenhouse gas emissions reductions, 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.

Note B — Asset Acquisitions and Divestitures

On June 30, 2022, the Company completed the sale of Seneca’s California assets, all of which are in the Exploration and Production segment, to Sentinel Peak Resources California LLC for a total sale price of $253.5 million, consisting of $240.9 million in cash and contingent consideration valued at $12.6 million at closing. The Company pursued this sale given the strong commodity price environment and the Company’s strategic focus in the Appalachian Basin. Under the terms of the purchase and sale agreement, the Company can receive up to three annual contingent payments between calendar year 2023 and calendar year 2025, not to exceed $10 million per year, with the amount of each annual payment calculated as $1.0 million for each $1 per barrel that the ICE Brent Average for each calendar year exceeds $95 per barrel up to $105 per barrel. The sale price, which reflected an effective date of April 1, 2022, was reduced for production revenues less expenses that were retained by Seneca from the effective date to the closing date. Under the full cost method of accounting for oil and natural gas properties, $220.7 million of the sale price at closing was accounted for as reduction of capitalized costs since the disposition did not alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center. The remainder of the sale price ($32.8 million) was applied against assets that are not subject to the full cost method of accounting, with the Company recognizing a gain of $12.7 million on the sale of such assets. The majority of this gain related to the sale of emission allowances. The Company also eliminated the asset retirement obligation associated with Seneca’s California oil and gas assets. This obligation amounted to $50.1 million and was accounted for as a reduction of capitalized costs under the full cost method of accounting.

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 reflected 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	$	506,258

	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	$	282,780		$	223,478		$ 506,258

(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").

On December 10, 2020, the Company completed the sale of substantially all timber properties in Pennsylvania to Lyme Emporium Highlands III LLC and Lyme Allegheny Land Company II LLC for net proceeds of $104.6 million. These assets were a component of the Company's All Other category and did not have a major impact on the Company's operations or financial results. After purchase price adjustments and transaction costs, a gain of $51.1 million was recognized on the sale of these assets. Since the sale did not represent a strategic shift in focus for the Company, the financial results associated with operating these assets as well as the gain on sale have not been reported as discontinued operations.

The sale of the timber properties completed the Reverse 1031 Exchange related to the Company's acquisition of certain upstream assets and midstream gathering assets in Pennsylvania from Shell, as discussed above. In connection with the Reverse 1031 Exchange, the Company, through a subsidiary, assigned the rights to acquire legal title to certain oil and natural gas properties to a Variable Interest Entity ("VIE") formed by an exchange accommodation titleholder. The Company evaluated the VIE to determine whether the Company should be considered as the primary beneficiary having a controlling financial interest. It was determined that the Company had the power to direct the activities of the VIE and the obligation to absorb significant losses of that entity or the right to receive significant benefits from that entity. Therefore, the Company was considered to be the primary beneficiary. From July 31, 2020 to December 10, 2020, a subsidiary of the Company operated the properties pursuant to a lease agreement with the VIE. As the Company was deemed to be the primary beneficiary of the VIE, the VIE was included in the consolidated financial statements of the Company. Upon completion of the sale of the timber properties on December 10, 2020, the affected properties were conveyed to the Company and the VIE structure was terminated.

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. This sale, in conjunction with the turn back of NFR's residential customers to Distribution Corporation, effectively ended NFR's operations. 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.

Note C — Revenue from Contracts with Customers

The following tables provide a disaggregation of the Company's revenues for the years ended September 30, 2022 and 2021, presented by type of service from each reportable segment.

	Year Ended September 30, 2022							
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	$ 1,730,723	$ —	$ —	$ —	$ 1,730,723	$ —	$ —	$ 1,730,723
Production of Crude Oil	150,957	—	—	—	150,957	—	—	150,957
Natural Gas Processing	3,511	—	—	—	3,511	—	—	3,511
Natural Gas Gathering Service	—	—	214,843	—	214,843	—	(202,757)	12,086
Natural Gas Transportation Service	—	289,967	—	106,495	396,462	—	(74,749)	321,713
Natural Gas Storage Service	—	84,565	—	—	84,565	—	(36,382)	48,183
Natural Gas Residential Sales	—	—	—	688,271	688,271	—	—	688,271
Natural Gas Commercial Sales	—	—	—	95,114	95,114	—	—	95,114
Natural Gas Industrial Sales	—	—	—	4,902	4,902	—	—	4,902
Other	7,867	2,512	—	(3,918)	6,461	6	(644)	5,823
Total Revenues from Contracts with Customers	1,893,058	377,044	214,843	890,864	3,375,809	6	(314,532)	3,061,283
Alternative Revenue Programs	—	—	—	7,357	7,357	—	—	7,357
Derivative Financial Instruments	(882,594)	—	—	—	(882,594)	—	—	(882,594)
Total Revenues	$ 1,010,464	$ 377,044	$ 214,843	$ 898,221	$ 2,500,572	$ 6	$ (314,532)	$ 2,186,046

Revenues by Type of Service	Year Ended September 30, 2021							
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Production of Natural Gas	$ 780,477	$ —	$ —	$ —	$ 780,477	$ —	$ —	$ 780,477
Production of Crude Oil	135,191	—	—	—	135,191	—	—	135,191
Natural Gas Processing	2,960	—	—	—	2,960	—	—	2,960
Natural Gas Gathering Service	—	—	193,264	—	193,264	—	(190,148)	3,116
Natural Gas Transportation Service	—	255,849	—	103,141	358,990	—	(72,920)	286,070
Natural Gas Storage Service	—	83,080	—	—	83,080	—	(35,841)	47,239
Natural Gas Residential Sales	—	—	—	492,567	492,567	—	—	492,567
Natural Gas Commercial Sales	—	—	—	62,634	62,634	—	—	62,634
Natural Gas Industrial Sales	—	—	—	3,071	3,071	—	—	3,071
Natural Gas Marketing	—	—	—	—	—	678	(49)	629
Other	2,042	4,628	—	(5,249)	1,421	544	(374)	1,591
Total Revenues from Contracts with Customers	920,670	343,557	193,264	656,164	2,113,655	1,222	(299,332)	1,815,545
Alternative Revenue Programs	—	—	—	11,087	11,087	—	—	11,087
Derivative Financial Instruments	(83,973)	—	—	—	(83,973)	—	—	(83,973)
Total Revenues	$ 836,697	$ 343,557	$ 193,264	$ 667,251	$ 2,040,769	$ 1,222	$ (299,332)	$ 1,742,659

The Company records revenue related to its derivative financial instruments in the Exploration and Production segment. The Company also records revenue related to alternative revenue programs in its Utility segment. Revenue related to derivative financial instruments and alternative revenue programs are excluded from the scope of the authoritative guidance regarding revenue recognition since they are accounted for under other existing accounting guidance.

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. Prior to the completion of the sale of the Company's California assets on June 30, 2022, natural gas production occurred primarily in the Appalachian region of the United States and crude oil production occurred primarily in the West Coast region of the United States. Subsequent to June 30, 2022, substantially all Exploration and Production segment production consists of natural gas production from the Appalachian region of the United States. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance. The sales contracts generally require the Company to deliver a specific quantity of a commodity per day for a specific number of days at a price that is either fixed or variable and considers the delivery of each unit (MMBtu or Bbl) to be a separate performance obligation that is satisfied upon delivery.

The transaction price for the sale of natural gas, oil and NGLs is contractually agreed upon based on prevailing market pricing (primarily tied to a market index with certain adjustments based on factors such as delivery location and prevailing supply and demand conditions) or fixed pricing. The Company allocates the transaction price to each performance obligation on the basis of the relative standalone selling price of each distinct unit sold. Revenue is recognized at a point in time when the transfer of the commodity occurs at the delivery point per the contract. The amount billable, as determined by the contracted quantity and price, indicates the value to the customer, and is used for revenue recognition purposes by the Exploration and Production segment as specified by the "invoice practical expedient" (the amount that the Exploration and

Production segment has the right to invoice) under the authoritative guidance for revenue recognition. The contracts typically require payment within 30 days of the end of the calendar month in which the natural gas and oil is delivered, or picked up in the case of NGLs.

The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment related to sales of the natural gas 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: $212.4 million for fiscal 2023; $191.0 million for fiscal 2024; $166.9 million for fiscal 2025; $143.8 million for fiscal 2026; $121.1 million for fiscal 2027; and $691.7 million thereafter.

Gathering Segment Revenue

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

Utility Segment Revenue

The Company's Utility segment records revenue for natural gas sales and natural gas transportation services in western New York and northwestern Pennsylvania at tariff-based rates regulated by the NYPSC and the PaPUC, respectively. 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 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.

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. The Company did not have any material finance leases as of September 30, 2022 or September 30, 2021. Aside from a sublease of office space at the Company's corporate headquarters, which terminated April 30th, 2022, the Company does not have any material arrangements where the Company is the lessor.

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 two months to seventeen 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 eighteen 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.

Drilling Rigs

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

Drilling rig lease costs are capitalized as part of natural gas properties on the Consolidated Balance Sheet when incurred.

Compressor Equipment

The Company enters into contracts for compressor services with third parties primarily to support its gathering system in Pennsylvania. The primary non-cancelable terms of the Company's compressor equipment leases range from 21 months to 4 years. Most compressor equipment leases include one or more options to renew or to continue past the primary term on a month-to-month basis, generally at the Company's sole discretion. Renewal options are included in the lease term if they are reasonably certain to be exercised.

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.

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.

Gas Leases

The authoritative guidance does not apply to leases to explore for or use natural gas resources, including the right to explore for those resources and rights to use the land in which those resources are contained. As such, the Company has concluded that its 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 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	
	2022	**2021**
Operating Lease Expense	$ 4,909	$ 5,268
Variable Lease Expense(1)	462	537
Short-Term Lease Expense(2)	461	1,279
Sublease Income	(166)	(356)
Total Lease Expense	$ 5,666	$ 6,728
Lease Costs Recorded to Property, Plant and Equipment(3)	$ 19,839	$ 14,188

(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) Lease costs relating to drilling rig leases that are capitalized as part of oil and natural gas properties under full cost pool accounting as well as certain equipment leases used on construction projects.

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. The weighted average remaining lease term was 6.0 years and 8.8 years as of September 30, 2022 and 2021, respectively. The weighted average discount rate was 3.92% and 4.24% as of September 30, 2022 and 2021, respectively.

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 Liabilities (noncurrent). Short-term leases that have a lease term of one year or less are not recorded on the Consolidated Balance Sheet.

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

	Year Ended September 30	
	2022	2021
Assets:		
Deferred Charges	$ 37,120	$ 23,601
Liabilities:		
Other Accruals and Current Liabilities	$ 14,239	$ 3,963
Other Liabilities	$ 22,881	$ 19,638

Cash paid for lease liabilities, and reported in cash provided by operating activities on the Company's Consolidated Statement of Cash Flows, was $5.7 million and $6.7 million for the years ended September 30, 2022 and 2021, respectively. The Company did not record any right-of-use assets in exchange for new lease liabilities during the years ended September 30, 2022 or 2021.

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, 2022 (in thousands):

	At September 30, 2022
2023	$ 14,420
2024	5,353
2025	4,828
2026	3,578
2027	2,889
Thereafter	11,656
Total Lease Payments	42,724
Less: Interest	(5,604)
Total Lease Liability	$ 37,120

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 natural gas wells and has capitalized such costs in property, plant and equipment (i.e. the full cost pool). During fiscal 2021, this segment's Appalachian operations were required to implement additional water testing on a portion of its assets, which contributed to an increase in the asset retirement obligation. This increase is the primary component of the Revisions of Estimates amount for fiscal 2021 shown in the table below.

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. Asset retirement obligation costs related to storage tanks have been recorded in the Utility, Pipeline and Storage, and Gathering 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 June 30, 2022, the Company completed the sale of Seneca's California oil and gas assets to Sentinel Peak Resources California LLC. With the divestiture of these assets, the Company reduced its Asset Retirement Obligation at June 30, 2022 by \$50.1 million. This reduction is reflected in Liabilities Settled in the table below.

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 Obligation 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		
	2022	2021	2020
		(Thousands)	
Balance at Beginning of Year	$ 209,639	$ 192,228	$ 127,458
Liabilities Incurred	2,401	7,035	61,246
Revisions of Estimates	10,700	14,509	3,267
Liabilities Settled	(71,171)	(14,270)	(7,268)
Accretion Expense	9,976	10,137	7,525
Balance at End of Year	$ 161,545	$ 209,639	$ 192,228

Note F — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30 2022	At September 30 2021
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note K)	$ 11,677	$ 21,655
Post-Retirement Benefit Costs(2) (Note K)	6,814	10,075
Recoverable Future Taxes (Note G)	106,247	121,992
Environmental Site Remediation Costs(2) (Note L)	3,646	7,256
Asset Retirement Obligations(2) (Note E)	18,517	16,799
Unamortized Debt Expense (Note A)	8,884	10,589
Other(3)	47,805	33,566
Total Regulatory Assets	203,590	221,932
Less: Amounts Included in Other Current Assets	(21,358)	(29,206)
Total Long-Term Regulatory Assets	$ 182,232	$ 192,726

	At September 30 2022	At September 30 2021
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	$ 259,947	$ 245,636
Taxes Refundable to Customers (Note G)	362,098	354,089
Post-Retirement Benefit Costs(5) (Note K)	167,305	213,112
Pension Costs(4) (Note K)	8,242	—
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	419	21
Other(6)	44,549	48,391
Total Regulatory Liabilities	842,560	861,249
Less: Amounts included in Current and Accrued Liabilities	(31,712)	(60,881)
Total Long-Term Regulatory Liabilities	$ 810,848	$ 800,368

(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) $21,358 and $29,206 are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $26,447 and $4,360 are included in Other Regulatory Assets on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively.

(4) Included in Other Regulatory Liabilities on the Consolidated Balance Sheets.

(5) $5,800 and $30,000 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively, since such amounts are expected to be passed back to ratepayers in the next 12 months. $161,505 and $183,112 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively.

(6) $25,493 and $30,860 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2022 and 2021, respectively, since such amounts are expected to be passed back to ratepayers in the next 12 months. $19,056 and $17,531 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2022 and 2021, 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 customers 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%, and directed the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018. The order also authorized the Company to recover approximately $15 million annually for pension and OPEB expenses from customers. Because the Company’s future pension and OPEB costs were projected to be satisfied with existing funds held in reserve, in July, Distribution Corporation made a filing with the NYPSC to effectuate a pension and OPEB surcredit to customers to offset these amounts being collected in base rates effective October 1, 2022. On September 16, 2022, the NYPSC issued an order approving the filing. With the implementation of this surcredit, Distribution Corporation will no longer be funding the pension from its New York jurisdiction and it will not be funding its VEBA trusts in its New York jurisdiction.

Pennsylvania Jurisdiction

Distribution Corporation’s current delivery rates in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007. On October 28, 2022, Distribution Corporation made a filing with the PaPUC seeking an increase in its annual base rate operating revenues of $28.1 million with a proposed effective date of December 27, 2022. The Company is also proposing, among other things, to implement a weather normalization adjustment mechanism and a new energy efficiency and conservation pilot program for residential customers. The filing will be suspended for seven months by operation of law unless directed otherwise by the PaPUC.

Effective October 1, 2021, pursuant to a tariff supplement filed with the PaPUC, Distribution Corporation reduced base rates by $7.7 million in order to stop collecting OPEB expenses from customers. It also began to refund customers overcollected OPEB expenses in the amount of $50.0 million. Certain other matters in the tariff supplement were unresolved. These matters were resolved with the PaPUC’s approval of an Administrative Law Judge’s Recommended Decision on February 24, 2022. Concurrent with that decision, the Company discontinued regulatory accounting for OPEB expenses and recorded an $18.5 million adjustment during the quarter ended March 31, 2022 to reduce its regulatory liability for previously deferred OPEB income amounts through September 30, 2021 and to increase Other Income (Deductions) on the consolidated financial statements by a like amount. The Company also increased customer refunds of overcollected OPEB expenses from $50.0 million to $54.0 million. All refunds specified in the tariff supplement are being funded entirely by grantor trust assets held by the Company, most of which are included in a fixed income mutual fund that is a component of Other Investments on the Company's Consolidated Balance Sheet. With the elimination of OPEB expenses in base rates, Distribution Corporation is no longer funding the grantor trust or its VEBA trusts in its Pennsylvania jurisdiction.

FERC Jurisdiction

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

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

Note G — Income Taxes

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

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Current Income Taxes —			
Federal	$ —	$ (10)	$ (42,548)
State	12,214	8,699	6,974
Deferred Income Taxes —			
Federal	137,025	90,970	4,538
State	(32,610)	15,023	49,775
Total Income Taxes	$ 116,629	$ 114,682	$ 18,739

On 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 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.

On July 8, 2022, House Bill 1342 was signed into law in Pennsylvania. The law reduces the corporate income tax rate to 8.99% for fiscal 2024. Starting with fiscal 2025, the rate is reduced by 0.5% annually until it reaches 4.99% for fiscal 2032. Under GAAP, the tax effects of a change in tax law must be recognized in the period in which the law is enacted. GAAP also requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. The Company's deferred income taxes were re-measured based upon the new tax rates. For the Company's non-rate regulated activities, the change in deferred income taxes was $28.4 million as of the enactment date and was recorded as a reduction to income tax expense. For the Company's rate regulated activities, the reduction in deferred income taxes of $37.2 million was recorded as a decrease to Recoverable Future Taxes of $19.8 million and an increase to Taxes Refundable to Customers of $17.4 million.

On August 16, 2022, the "Inflation Reduction Act" (IRA) was signed into law. The IRA, among other things, includes provisions to expand energy incentives and impose a corporate minimum tax. The provisions of the IRA did not have a material impact on the fiscal 2022 financial statements, although some of the provisions may be applicable in future years.

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

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
U.S. Income (Loss) Before Income Taxes (1)	$ 682,650	$ 478,327	$ (105,046)
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate of 21%	$ 143,357	$ 100,449	$ (22,060)
State Valuation Allowance (2)	(24,850)	(5,560)	63,205
State Income Taxes (Benefit) (3)	8,736	24,300	(18,374)
Amortization of Excess Deferred Federal Income Taxes	(5,184)	(5,215)	(4,749)
Plant Flow Through Items	(814)	(1,503)	(2,848)
Stock Compensation	820	2,239	3,867
Federal Tax Credits	(5,701)	(310)	(217)
Miscellaneous	265	282	(85)
Total Income Taxes	$ 116,629	$ 114,682	$ 18,739

(1) Amounts include the impact of deferred investment tax credits reported in Other Income (Deductions) on the Consolidated Statements of Income.
(2) During fiscal 2020, a valuation allowance was recorded against certain state deferred tax assets. During fiscal 2022, the valuation allowance was removed. See discussion below.
(3) The state income tax expense (benefit) shown above includes adjustments to the estimated state effective tax rates utilized in the calculation of deferred income taxes, including the Pennsylvania rate change discussed above.

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

	At September 30	
	2022	2021
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 954,757	$ 920,692
Pension and Other Post-Retirement Benefit Costs	30,132	23,240
Other	48,893	35,081
Total Deferred Tax Liabilities	1,033,782	979,013
Deferred Tax Assets:		
Unrealized Hedging Losses	(215,187)	(170,155)
Tax Loss and Credit Carryforwards	(50,686)	(120,725)
Pension and Other Post-Retirement Benefit Costs	(37,250)	(53,765)
Other	(32,430)	(31,593)
Total Gross Deferred Tax Assets	(335,553)	(376,238)
Valuation Allowance	—	57,645
Total Deferred Tax Assets	(335,553)	(318,593)
Total Net Deferred Income Taxes	$ 698,229	$ 660,420

The following is a summary of changes in valuation allowances for deferred tax assets:

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
Balance at Beginning of Year	$ 57,645	$ 63,205	$ —
Additions	—	—	63,205
Deductions	57,645	5,560	—
Balance at End of Year	$ —	$ 57,645	$ 63,205

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, at each reporting date, 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 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. On June 30, 2022, the Company completed the sale of Seneca's California oil and gas assets to Sentinel Peak Resources California, LLC. As a result of the sale of the California oil and gas assets, the remaining deferred tax assets and valuation allowance of approximately $27.2 million related to the California net operating loss and tax credit carryforwards were written off. The deferred tax assets and valuation allowance were written off as the Company determined that there was a remote possibility for use as the Company no longer has California operations. During the quarter ended September 30, 2022, the valuation allowance was adjusted because of the Pennsylvania corporate income tax rate change remeasurement described above and for current activity for a cumulative adjustment of $5.5 million. In addition, the Company determined there was sufficient positive evidence, despite a prior history of subsidiary tax losses, to conclude that it was more likely than not that the remaining state deferred tax assets would be realized. The conclusion was primarily related to the use of net operating losses in Pennsylvania in the current year due to sustained strong operating results as well as the expectation for future forecasted earnings in Pennsylvania due to increased natural gas prices. The sale of California assets will also result in higher apportionment of income to Pennsylvania on a prospective basis, further supporting realization of existing Pennsylvania net operating loss deferred tax assets. Accordingly, the Company reversed the remaining valuation allowance and recognized an income tax benefit of approximately $24.9 million.

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 $362.1 million and $354.1 million at September 30, 2022 and 2021, 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 $106.2 million and $122.0 million at September 30, 2022 and 2021, respectively.

The Company is in the Bridge Phase of the IRS Compliance Assurance Process (“CAP”) for fiscal 2022. The Bridge Phase is intended for taxpayers with a low risk of non-compliance who are cooperative and transparent with few, if any, material issues that require resolution. The IRS will not accept any disclosures, conduct any reviews, or provide any letters of assurance for the Bridge year. The federal statute of limitations remains open for fiscal 2019 and later years. The Company is also subject to various routine state income tax examinations. The Company’s principal subsidiaries have state 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. The Company has no unrecognized tax benefits as of September 30, 2022, 2021, or 2020.

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, 2022, were as follows:

Jurisdiction	Tax Attribute	Amount (Thousands)	Expires
Pennsylvania	Net Operating Loss	$ 378,631	2030-2042
Federal	General Business Credits	20,677	2035-2042

Note H — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock Shares	Common Stock Amount	Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Loss
	(Thousands, except per share amounts)				
Balance at September 30, 2019	86,315	$86,315	$ 832,264	$1,272,601	$ (52,155)
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	90,955	90,955	1,004,158	991,630	(114,757)
Net Income Available for Common Stock				363,647	
Dividends Declared on Common Stock ($1.80 Per Share)				(164,102)	
Other Comprehensive Loss, Net of Tax					(398,840)
Share-Based Payment Expense(1)			15,297		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	227	227	(2,009)		
Balance at September 30, 2021	91,182	91,182	1,017,446	1,191,175	(513,597)
Net Income Available for Common Stock				566,021	
Dividends Declared on Common Stock ($1.86 Per Share)				(170,111)	
Other Comprehensive Loss, Net of Tax					(112,136)
Share-Based Payment Expense(1)			17,699		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans	296	296	(8,079)		
Balance at September 30, 2022	91,478	$91,478	$1,027,066	$1,587,085 (2)	$ (625,733)

(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.

(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, 2022, $1.4 billion of accumulated earnings was free of such limitations.

Common Stock

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 2022, 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 2022, the Company issued 30,769 original issue shares of common stock as a result of SARs exercises, 129,169 original issue shares of common stock for restricted stock units that vested and 265,607 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 2022, 157,812 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, including the reinvestment of dividends for certain non-employee directors who elected to defer their shares pursuant to the dividend reinvestment feature of the Company's Deferred Compensation Plan for Directors and Officers, as partial consideration for the directors’ services during the fiscal year. Under this program, the Company issued 28,782 original issue shares of common stock during 2022.

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.

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, 2022, 2021 and 2020 was approximately $17.6 million, $15.2 million and $13.1 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, 2022, 2021 and 2020 was approximately $2.5 million, $2.4 million and $2.1 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, 2022, 2021 and 2020. The tax benefit related to stock-based compensation exercises and vestings was $0.6 million for the year ended September 30, 2022.

Pursuant to registration statements for these plans, there were 2,149,203 shares available for future grant at September 30, 2022. These shares include shares available for future options, SARs, restricted stock and performance share grants.

SARs

Transactions for 2022 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, 2021	318,445	$ 53.60		
Granted in 2022	—	$ —		
Exercised in 2022	(241,437)	$ 55.73		
Forfeited in 2022	—	$ —		
Expired in 2022	(5,000)	$ 55.09		
Outstanding at September 30, 2022	72,008	$ 53.05	0.22	$ 612
SARs exercisable at September 30, 2022	72,008	$ 53.05	0.22	$ 612

The Company did not grant any SARs during the years ended September 30, 2021 and 2020. 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, 2022 totaled approximately $2.0 million. During the years ended September 30, 2021 and 2020, no SARs were exercised. There were no SARs that became fully vested during the years ended September 30, 2022, 2021 and 2020, and all SARs outstanding have been fully vested since fiscal 2017.

Restricted Stock Units

Transactions for 2022 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, 2021	365,481	$ 41.45
Granted in 2022	128,950	$ 54.10
Vested in 2022	(129,169)	$ 45.24
Forfeited in 2022	(17,835)	$ 44.61
Outstanding at September 30, 2022	347,427	$ 44.58

The Company also granted 172,513 and 150,839 nonperformance-based restricted stock units during the years ended September 30, 2021 and 2020, respectively. The weighted average fair value of such nonperformance-based restricted stock units granted in 2021 and 2020 was $37.98 per share and $40.38 per share, respectively. As of September 30, 2022, unrecognized compensation expense related to nonperformance-based restricted stock units totaled approximately $6.4 million, which will be recognized over a weighted average period of 2.2 years.

Vesting restrictions for the nonperformance-based restricted stock units outstanding at September 30, 2022 will lapse as follows: 2023 — 119,612 units; 2024 — 97,614 units; 2025 — 73,797 units; 2026 — 37,052 units; and 2027 — 19,352 units.

Performance Shares

Transactions for 2022 involving performance shares for all plans are summarized as follows:

	Number of Performance Shares	Weighted Average Fair Value per Award
Outstanding at September 30, 2021	600,634	$ 45.13
Granted in 2022	195,397	$ 65.39
Vested in 2022	(265,607)	$ 55.93
Forfeited in 2022	(23,414)	$ 49.84
Change in Units Based on Performance Achieved	100,169	$ 56.36
Outstanding at September 30, 2022	607,179	$ 48.60

The Company also granted 309,470 and 254,608 performance shares during the years ended September 30, 2021 and 2020, respectively. The weighted average grant date fair value of such performance shares granted in 2021 and 2020 was $39.19 per share and $43.32 per share, respectively. As of September 30, 2022, unrecognized compensation expense related to performance shares totaled approximately $11.3 million, which will be recognized over a weighted average period of 1.8 years. Vesting restrictions for the outstanding performance shares at September 30, 2022 will lapse as follows: 2023 — 199,842 shares; 2024 — 220,914 shares; and 2025 — 186,423 shares.

The performance shares granted during the years ended September 30, 2022, 2021 and 2020 include awards that must meet a performance goal related to either relative return on capital over a three-year performance cycle ("ROC performance shares"), methane intensity and greenhouse gas emissions reductions over a three-year performance cycle ("ESG performance shares") or relative shareholder return over a three-year performance cycle ("TSR performance shares"). The performance goal over the respective performance cycles for the ROC performance shares granted during 2022, 2021 and 2020 is the Company’s total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee (“Report Group”). Total return on capital for a given company means the average of the Report Group companies’ returns on capital for each twelve-month period corresponding to each of the Company’s fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these ROC 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 the ROC 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 performance goal over the performance cycle for the ESG performance shares granted during 2022 consists of two parts: reductions in the rates of intensity of methane emissions for each of the Company's operating segments, and reduction of the consolidated Company's total greenhouse gas emissions. The Company's Compensation Committee set specific target levels for methane intensity rates and total greenhouse gas emissions, and the performance goal is intended to incentivize and reward performance that helps position the Company to meet or exceed its 2030 methane intensity and greenhouse gas reduction targets. The number of these ESG performance shares that will vest and be paid out will depend upon the number of methane intensity segment targets achieved and whether the Company meets the total greenhouse gas emissions target. The fair value of these ESG 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. There were no ESG performance shares granted in 2021 and 2020.

The performance goal over the respective performance cycles for the TSR performance shares granted during 2022, 2021 and 2020 is the Company's three-year total shareholder return relative to the three-year total shareholder return of the other companies in the Report Group. Three-year total shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company's securities at each ex-dividend date) in the Bloomberg database. The number of these 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		
	2022	2021	2020
Risk-Free Interest Rate	0.85 %	0.19 %	1.63 %
Remaining Term at Date of Grant (Years)	2.80	2.80	2.81
Expected Volatility	29.7 %	29.1 %	19.3 %
Expected Dividend Yield (Quarterly)	N/A	N/A	N/A

Redeemable Preferred Stock

As of September 30, 2022, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

Long-Term Debt

The outstanding long-term debt is as follows:

	At September 30	
	2022	2021
	(Thousands)	
Medium-Term Notes(1):		
7.4% due March 2023 to June 2025	$ 99,000	$ 99,000
Notes(1)(2)(3):		
2.95% to 5.50% due March 2023 to March 2031	2,550,000	2,550,000
Total Long-Term Debt	2,649,000	2,649,000
Less Unamortized Discount and Debt Issuance Costs	16,591	20,313
Less Current Portion(4)	549,000	—
	$ 2,083,409	$ 2,628,687

(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, $300.0 million of 3.95% notes and $500.0 million of 2.95% 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 adjustment from time to time, with 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 to a rating below investment grade. 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) Current Portion of Long-Term Debt at September 30, 2022 consists of $500.0 million of 3.75% notes and $49.0 million of 7.395% notes that each mature in March 2023. The Company has committed to redeeming $150.0 million of the 3.75% notes on November 25, 2022. None of the Company's long-term debt as of September 30, 2021 had a maturity date within the following twelve-month period.

On February 24, 2021, the Company issued $500.0 million of 2.95% notes due March 1, 2031. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $495.3 million. The proceeds of this debt issuance were used for general corporate purposes, including the redemption of $500.0 million of 4.90% notes on March 11, 2021 that were scheduled to mature in December 2021. The Company redeemed those notes for $515.7 million, plus accrued interest. The early redemption premium of $15.7 million was recorded to Interest Expense on Long-Term Debt on the Consolidated Income Statement during the quarter ended March 31, 2021.

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.

As of September 30, 2022, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $549.0 million in 2023, zero in 2024, $500.0 million in 2025, $500.0 million in 2026, $300.0 million in 2027, and $800.0 million thereafter.

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. On February 28, 2022, the Company entered into a Credit Agreement (as amended from time to time, the "Credit Agreement") with a syndicate of twelve banks. The Credit Agreement replaced the previous Fourth Amended and Restated Credit Agreement and a previous 364-Day Credit Agreement. The Credit Agreement provides a $1.0 billion unsecured committed revolving credit facility with a maturity date of February 26, 2027.

On June 30, 2022, the Company entered into a new 364-Day Credit Agreement (the "364-Day Credit Agreement") with a syndicate of five banks, all of which are also lenders under the Credit Agreement. The 364-Day Credit Agreement provides an additional $250.0 million unsecured committed delayed draw term loan credit facility with a maturity date of June 29, 2023. The Company elected to draw $250.0 million under the facility on October 27, 2022. The Company is using the proceeds for general corporate purposes, which will include the redemption in November of a portion of the Company's outstanding long-term debt maturing in March 2023.

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.

At September 30, 2022, the Company had outstanding short-term notes payable to banks of $60.0 million, all of which was issued under the Credit Agreement, with an interest rate of 4.02%. The Company did not have any outstanding commercial paper at September 30, 2022. The Company had outstanding commercial paper of $158.5 million at September 30, 2021, with a weighted average interest rate on the commercial paper of 0.40%. The Company did not have any outstanding short-term notes payable to banks at September 30, 2021.

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 $400 million. Since July 1, 2018, the Company recorded non-cash, after-tax ceiling test impairments totaling $381.4 million. As a result, at September 30, 2022, $190.7 million was added back to the Company's total capitalization for purposes of the calculation under the Credit Agreement and 364-Day Credit Agreement. On May 3, 2022, the Company entered into Amendment No. 1 to the Credit Agreement with the same twelve banks under the initial Credit Agreement. The amendment further modified the definition of consolidated capitalization, for purposes of calculating the debt to capitalization ratio under the Credit Agreement, to exclude, beginning with the quarter ended June 30, 2022, all unrealized gains or losses on commodity-related derivative financial instruments and up to $10 million in unrealized gains or losses on other derivative financial instruments included in Accumulated Other Comprehensive Income (Loss) within Total Comprehensive Shareholders' Equity on the Company's consolidated balance sheet. Under the Credit Agreement, such unrealized losses will not negatively affect the calculation of the debt to capitalization ratio, and such unrealized gains will not positively affect the calculation. The 364-Day Credit Agreement includes the same debt to capitalization covenant and the same exclusions of unrealized gains or losses on derivative financial instruments as the Credit Agreement. At September 30, 2022, the Company's debt to capitalization ratio, as calculated under the Credit Agreement and 364-Day Credit Agreement, was .49. The constraints specified in the Credit Agreement and 364-Day Credit Agreement would have permitted an additional $2.56 billion in short-term and/or long-term debt to be outstanding at September 30, 2022 (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

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

The Credit Agreement and 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 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.

In order to issue incremental long-term debt, the Company must meet an interest coverage test under its existing indenture covenants. 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, taking into account the incremental issuance, and using a pro forma balance sheet as of the last day of the 12-month period used in the interest coverage test, the Company must maintain a ratio of long-term debt to consolidated assets (as defined under the indenture) of not more than 60%. Under the Company's existing indenture covenants at September 30, 2022, the Company would have been permitted to issue up to a maximum of approximately $2.0 billion in additional unsubordinated long-term indebtedness at then current market interest rates, in addition to being able to issue new indebtedness to replace existing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. It is possible, depending on amounts reported in various income statement and balance sheet line items, that the indenture covenants could, for a period of time, prevent the Company from issuing incremental unsubordinated long-term debt, or significantly limit the amount of such debt that could be issued. Losses incurred as a result of significant impairments of oil and gas properties have in the past resulted in such temporary restrictions. The indenture covenants would not preclude the Company from issuing new long-term debt to replace existing long-term debt, or from issuing additional short-term debt. Please refer to 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, 2022) 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, 2022 and 2021. 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 have historically entered into both gas and oil swap agreements with the Company.

Recurring Fair Value Measures	At Fair Value as of September 30, 2022				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$ 35,015	$ —	$ —	$ —	$ 35,015
Hedging Collateral Deposits	91,670	—	—	—	91,670
Derivative Financial Instruments:					
Over the Counter Swaps — Gas	—	5,177	—	(4,178)	999
Contingent Consideration for Asset Sale	—	8,176	—	—	8,176
Foreign Currency Contracts	—	128	—	(128)	—
Other Investments:					
Balanced Equity Mutual Fund	19,506	—	—	—	19,506
Fixed Income Mutual Fund	33,348	—	—	—	33,348
Total	$ 179,539	$ 13,481	$ —	$ (4,306)	$ 188,714
Liabilities:					
Derivative Financial Instruments:					
Over the Counter Swaps — Gas	$ —	$ 517,464	$ —	$ (4,178)	$ 513,286
Over the Counter No Cost Collars — Gas	—	270,453	—	—	270,453
Foreign Currency Contracts	—	2,048	—	(128)	1,920
Total	$ —	$ 789,965	$ —	$ (4,306)	$ 785,659
Total Net Assets/(Liabilities)	$ 179,539	$(776,484)	$ —	$ —	$(596,945)

Recurring Fair Value Measures	At Fair Value as of September 30, 2021				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$ 22,269	$ —	$ —	$ —	$ 22,269
Hedging Collateral Deposits	88,610	—	—	—	88,610
Derivative Financial Instruments:					
Over the Counter Swaps — Gas and Oil	—	1,802	—	(1,802)	—
Foreign Currency Contracts	—	938	—	(938)	—
Other Investments:					
Balanced Equity Mutual Fund	34,433	—	—	—	34,433
Fixed Income Mutual Fund	70,639	—	—	—	70,639
Total	$ 215,951	$ 2,740	$ —	$ (2,740)	$ 215,951
Liabilities:					
Derivative Financial Instruments:					
Over the Counter Swaps — Gas and Oil	$ —	$ 601,551	$ —	$ (1,802)	$ 599,749
Over the Counter No Cost Collars — Gas	—	17,385	—	—	17,385
Foreign Currency Contracts	—	214	—	(938)	(724)
Total	$ —	$ 619,150	$ —	$ (2,740)	$ 616,410
Total Net Assets/(Liabilities)	$ 215,951	$(616,410)	$ —	$ —	$(400,459)

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

Derivative Financial Instruments

At September 30, 2022, the derivative financial instruments reported in Level 2 consist of natural gas price swap agreements, natural gas no cost collars, and foreign currency contracts, all of which are used in the Company's Exploration and Production segment. The derivative financial instruments reported in Level 2 at September 30, 2021 consist of the same type of instruments in addition to crude oil price swap agreements. The use of crude oil price swap agreements was discontinued during the year ended September 30, 2022 in conjunction with the sale of the Exploration and Production segment's California assets. Hedging collateral deposits of $91.7 million (at September 30, 2022) and $88.6 million (at September 30, 2021), which were associated with the price swap agreements, no cost collars and foreign currency contracts, have been reported in Level 1.

The fair value of the Level 2 price swap agreements and no cost collars is based on an internal cash flow model that uses observable inputs (i.e. LIBOR based discount rates for the price swap agreements 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, 2022 and September 30, 2021 are determined using the market approach based on observable market transactions of forward Canadian currency rates.

The authoritative guidance for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2022, the Company determined that nonperformance risk associated with the price swap agreements, no cost collars and foreign currency contracts 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.

Derivative financial instruments reported in Level 2 at September 30, 2022 also includes the contingent consideration associated with the sale of the Exploration and Production segment's California assets on June 30, 2022, which is discussed at Note B — Asset Acquisitions and Divestitures and at Note J — Financial Instruments. The fair value of the contingent consideration was calculated using a Monte Carlo simulation model that uses observable inputs, including the ICE Brent closing price as of the valuation date, initial and max trigger price, volatility, risk free rate, time of maturity and counterparty risk.

For the years ended September 30, 2022 and 2021, there were no assets or liabilities measured at fair value and classified as Level 3.

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			
	2022 Carrying Amount	2022 Fair Value	2021 Carrying Amount	2021 Fair Value
	(Thousands)			
Long-Term Debt	$ 2,632,409	$ 2,453,209	$ 2,628,687	$ 2,898,552

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 for the risk-free component and company specific credit spread information — generally obtained from recent trade activity in the debt). As such, the Company considers the debt to be Level 2.

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

Other Investments

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

	At September 30	
	2022	2021
	(Thousands)	
Life Insurance Contracts	$ 42,171	$ 44,560
Equity Mutual Fund	19,506	34,433
Fixed Income Mutual Fund	33,348	70,639
	$ 95,025	$ 149,632

Investments in life insurance contracts are stated at their cash surrender values or net present value. Investments in an equity mutual fund and a fixed income mutual fund are stated at fair value based on quoted market prices with changes in fair value recognized in net income. The insurance contracts and equity mutual fund are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees. The fixed income mutual fund is primarily an informal funding mechanism for certain regulatory obligations that the Company has to Utility segment customers in its Pennsylvania jurisdiction, as discussed in Note F — Regulatory Matters, and 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 to manage the price risk associated with forecasted sales of natural gas. 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 8 years.

On June 30, 2022, the Company completed the sale of Seneca's California assets. Under the terms of the purchase and sale agreement, the Company can receive up to three annual contingent payments between calendar year 2023 and calendar year 2025, not to exceed $10 million per year, with the amount of each annual payment calculated as $1.0 million for each $1 per barrel that the ICE Brent Average for each calendar year exceeds $95 per barrel up to $105 per barrel. The Company has determined that this contingent consideration meets the definition of a derivative under the authoritative accounting guidance. Changes in the fair value of this contingent consideration are marked-to-market each reporting period, with changes in fair value recognized in Other Income (Deductions) on the Consolidated Statement of Income. The fair value of this contingent consideration was estimated to be $12.6 million and $8.2 million at June 30, 2022 and September 30, 2022, respectively. A $4.4 million mark-to-market adjustment was recorded during the quarter ended September 30, 2022.

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, 2022 and September 30, 2021.

Cash Flow Hedges

For derivative financial instruments that are designated and qualify as a cash flow hedge, the gain or loss on the derivative is reported as a component of other comprehensive income (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings.

As of September 30, 2022, the Company had 420.8 Bcf of natural gas commodity derivative contracts (swaps and no cost collars) outstanding.

As of September 30, 2022, the Company was hedging a total of $49.4 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts.

As of September 30, 2022, the Company had $784.7 million ($572.2 million after-tax) of net hedging losses included in the accumulated other comprehensive income (loss) balance. It is expected that $476.7 million ($347.6 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, 2022 and 2021 (Dollar Amounts in Thousands)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) for the Year Ended September 30,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income for the Year Ended September 30,	
	2022	2021		2022	2021
Commodity Contracts	$ (1,048,200)	$ (668,074)	Operating Revenue	$ (882,594) (1)	$ (83,973)
Foreign Currency Contracts	(2,631)	2,703	Operating Revenue	13	262
Total	$ (1,050,831)	$ (665,371)		$ (882,581)	$ (83,711)

(1) On June 30, 2022, the Company completed the sale of Seneca's California assets. Because of this sale, the Company terminated its remaining crude oil derivative contracts and discontinued hedge accounting for such contracts. A loss of $44.6 million was reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet to Operating Revenues on the Consolidated Statement of Income for the year ended September 30, 2022. This loss is included in the reported reclassification amounts.

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 nineteen counterparties of which one is in a net gain position. The Company had $1.0 million of credit exposure with the counterparty in a gain position at September 30, 2022. As of September 2022, 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, 2022, seventeen of the nineteen counterparties to the Company's outstanding derivative financial contracts (specifically the over-the-counter swaps, over-the-counter no cost collars and applicable foreign currency forward contracts) had a common credit-risk related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to post or 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 financial instrument contracts with a credit-risk contingency feature were in a liability position (or if the liability were larger) and/or the Company's credit rating declined, then hedging collateral deposits or an increase to such deposits could be required. At September 30, 2022, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $564.3 million according to the Company's internal model (discussed in Note I — Fair Value Measurements) and the Company posted $91.7 million in hedging collateral deposits. Depending on the movement of commodity prices in the future, it is possible that these liability positions could swing into asset positions, at which point the Company would be exposed to credit risk on its derivative financial instruments. In that case, the Company's counterparties could be required to post hedging collateral deposits.

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 $5.3 million, $4.8 million and $4.2 million for the years ended September 30, 2022, 2021 and 2020, 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 $7.8 million, $7.2 million, and $6.7 million for the years ended September 30, 2022, 2021 and 2020, 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.

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 2022, 2021 and 2020.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2022	2021	2020	2022	2021	2020
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 1,098,456	$ 1,139,105	$ 1,097,625	$ 431,213	$ 476,722	$ 468,163
Service Cost	8,758	9,865	9,318	1,328	1,602	1,609
Interest Cost	22,827	21,686	29,930	9,066	9,303	12,913
Plan Participants' Contributions	—	—	—	3,271	3,216	3,058
Retiree Drug Subsidy Receipts	—	—	—	312	1,244	1,411
Actuarial (Gain) Loss	(251,173)	(8,141)	65,908	(120,276)	(34,729)	16,396
Benefits Paid	(65,040)	(64,059)	(63,676)	(25,631)	(26,145)	(26,828)
Benefit Obligation at End of Period	$ 813,828	$ 1,098,456	$ 1,139,105	$ 299,283	$ 431,213	$ 476,722
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 1,095,729	$ 1,016,796	$ 968,449	$ 575,565	$ 547,885	$ 524,127
Actual Return on Plan Assets	(205,884)	122,992	87,402	(94,849)	47,541	44,448
Employer Contributions	20,400	20,000	24,621	3,082	3,068	3,080
Plan Participants' Contributions	—	—	—	3,271	3,216	3,058
Benefits Paid	(65,040)	(64,059)	(63,676)	(25,631)	(26,145)	(26,828)
Fair Value of Assets at End of Period	$ 845,205	$ 1,095,729	$ 1,016,796	$ 461,438	$ 575,565	$ 547,885
Net Amount Recognized at End of Period (Funded Status)	$ 31,377	$ (2,727)	$ (122,309)	$ 162,155	$ 144,352	$ 71,163
Amounts Recognized in the Balance Sheets Consist of:						
Non-Current Liabilities	$ —	$ (2,727)	$ (122,309)	$ (3,065)	$ (4,799)	$ (4,872)
Non-Current Assets	31,377	—	—	165,220	149,151	76,035
Net Amount Recognized at End of Period	$ 31,377	$ (2,727)	$ (122,309)	$ 162,155	$ 144,352	$ 71,163
Accumulated Benefit Obligation	$ 793,555	$ 1,060,659	$ 1,096,427	N/A	N/A	N/A
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	5.57 %	2.75 %	2.66 %	5.56 %	2.76 %	2.71 %
Rate of Compensation Increase	4.60 %	4.70 %	4.70 %	4.60 %	4.70 %	4.70 %

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2022	2021	2020	2022	2021	2020
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	$ 8,758	$ 9,865	$ 9,318	$ 1,328	$ 1,602	$ 1,609
Interest Cost	22,827	21,686	29,930	9,066	9,303	12,913
Expected Return on Plan Assets	(52,294)	(58,148)	(60,063)	(29,359)	(28,964)	(29,232)
Amortization of Prior Service Cost (Credit)	537	631	729	(429)	(429)	(429)
Recognition of Actuarial (Gain) Loss(1)	26,405	36,814	39,384	(7,610)	849	535
Net Amortization and Deferral for Regulatory Purposes	16,854	14,063	5,359	21,340	28,010	25,596
Net Periodic Benefit Cost (Income)	$ 23,087	$ 24,911	$ 24,657	$ (5,664)	$ 10,371	$ 10,992
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Effective Discount Rate for Benefit Obligations	2.75 %	2.66 %	3.15 %	2.76 %	2.71 %	3.17 %
Effective Rate for Interest on Benefit Obligations	2.14 %	1.96 %	2.81 %	2.17 %	2.01 %	2.84 %
Effective Discount Rate for Service Cost	2.95 %	3.01 %	3.31 %	3.00 %	3.20 %	3.39 %
Effective Rate for Interest on Service Cost	2.70 %	2.60 %	3.12 %	2.93 %	2.98 %	3.30 %
Expected Return on Plan Assets	5.20 %	6.00 %	6.40 %	5.20 %	5.40 %	5.70 %
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 (Income) 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 whose income level has exceeded certain IRS thresholds or who have been designated as participants 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, $8.3

million and $8.9 million in 2022, 2021 and 2020, respectively. The components of net periodic benefit cost other than service costs associated with these plans are presented in Other Income (Deductions) on the Consolidated Statements of Income. The accumulated benefit obligations for the plans were $64.9 million, $76.9 million and $78.7 million at September 30, 2022, 2021 and 2020, respectively. The projected benefit obligations for the plans were $77.2 million, $95.8 million and $98.1 million at September 30, 2022, 2021 and 2020, respectively. At September 30, 2022, $17.5 million of the projected benefit obligation is recorded in Other Accruals and Current Liabilities and the remaining $59.7 million is recorded in Other Liabilities on the Consolidated Balance Sheets. At September 30, 2021, $15.4 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $80.4 million was recorded in Other Liabilities on the Consolidated Balance Sheets. At September 30, 2020, $14.5 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $83.6 million was recorded in Other Liabilities on the Consolidated Balance Sheets. The weighted average discount rates for these plans were 5.49%, 2.15% and 1.92% as of September 30, 2022, 2021 and 2020, respectively and the weighted average rate of compensation increase for these plans was 8.00% as of September 30, 2022, 2021 and 2020.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2022, as well as the changes in such amounts during 2022, are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits	Non-Qualified Benefit Plans
		(Thousands)	
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Gain (Loss)	$ (86,133)	$ 14,569	$ (18,718)
Prior Service (Cost) Credit	(2,472)	1,543	—
Net Amount Recognized	$ (88,605)	$ 16,112	$ (18,718)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2022(1)			
Decrease (Increase) in Actuarial Loss, excluding amortization(2)	$ (7,006)	$ (3,932)	$ 8,222
Change due to Amortization of Actuarial Loss	26,405	(7,610)	6,301
Prior Service (Cost) Credit	537	(429)	—
Net Change	$ 19,936	$ (11,971)	$ 14,523

(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, 2022, the Company recorded a $1.9 million decrease to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a $20.6 million (pre-tax) increase to Accumulated Other Comprehensive Income.

The effect of the discount rate change for the Retirement Plan in 2022 was to decrease the projected benefit obligation of the Retirement Plan by $262.2 million. The mortality improvement projection scale was updated, which increased the projected benefit obligation of the Retirement Plan in 2022 by $1.8 million. Other actuarial experience increased the projected benefit obligation for the Retirement Plan in 2022 by $9.2 million. The effect of the discount rate change for the Retirement Plan in 2021 was to decrease the projected benefit obligation of the Retirement Plan by $11.2 million. 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 Company made cash contributions totaling $20.4 million to the Retirement Plan during the year ended September 30, 2022. The Company expects that the annual contribution to the Retirement Plan in 2023 will be in the range of zero to $8.0 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: $67.6 million in 2023; $67.7 million in 2024; $67.3 million in 2025; $66.9 million in 2026; $66.2 million in 2027; and $316.1 million in the five years thereafter.

The effect of the discount rate change in 2022 was to decrease the other post-retirement benefit obligation by $98.9 million. The mortality improvement projection scale was updated, which increased the other post-retirement benefit obligation in 2022 by $1.1 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2022 by $22.5 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 2021 was to decrease the other post-retirement benefit obligation by $2.5 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2021 by $2.0 million. The health care cost trend rates were updated, which decreased the other post-retirement benefit obligation in 2021 by $3.7 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2021 by $26.6 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 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 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):

	Benefit Payments	Subsidy Receipts
2023	$ 26,221	$ (1,829)
2024	$ 26,337	$ (1,929)
2025	$ 26,376	$ (2,014)
2026	$ 26,291	$ (2,096)
2027	$ 26,140	$ (2,162)
2028 through 2032	$ 125,765	$ (11,391)

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

	2022	2021	2020
Rate of Medical Cost Increase for Pre Age 65 Participants	5.30 % (1)	5.38 % (1)	5.42 % (2)
Rate of Medical Cost Increase for Post Age 65 Participants	4.84 % (1)	4.84 % (1)	4.75 % (2)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	6.29 % (1)	6.53 % (1)	6.80 % (2)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	4.84 % (1)	4.84 % (1)	4.75 % (2)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	5.96 % (1)	6.15 % (1)	6.20 % (2)

(1) It was assumed that this rate would gradually decline to 4% by 2046.
(2) It was assumed that this rate would gradually decline to 4.5% by 2039.

The Company made cash contributions totaling $2.8 million to its VEBA trusts during the year ended September 30, 2022. 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, 2022. The Company does not expect to make any contributions to its VEBA trusts in 2023.

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, 2022 and 2021, 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):

	At September 30, 2022				
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(7)
Retirement Plan Investments					
Domestic Equities(1)	$ 41,633	$ 41,633	$ —	$ —	$ —
International Equities(2)	1,363	—	—	—	1,363
Global Equities(3)	44,434	—	—	—	44,434
Domestic Fixed Income(4)	658,833	—	579,606	—	79,227
International Fixed Income(5)	7,782	—	7,782	—	—
Real Estate	140,739	—	—	—	140,739
Cash Held in Collective Trust Funds	17,388	—	—	—	17,388
Total Retirement Plan Investments	912,172	41,633	587,388	—	283,151
401(h) Investments	(73,044)	(3,310)	(46,694)	—	(23,040)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 839,128	$ 38,323	$ 540,694	$ —	$ 260,111
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	6,077				
Total Retirement Plan Assets	$ 845,205				

	At September 30, 2021				
	Total Fair Value	Level 1	Level 2	Level 3	Measured at NAV(7)
Retirement Plan Investments					
Domestic Equities(1)	$ 56,511	$ 146	$ —	$ —	$ 56,365
International Equities(2)	28,917	—	—	—	28,917
Global Equities(3)	95,865	—	—	—	95,865
Domestic Fixed Income(4)	818,361	1,447	758,417	—	58,497
International Fixed Income(5)	13,773	—	13,773	—	—
Global Fixed Income(6)	42,454	—	—	—	42,454
Real Estate	119,451	—	—	319	119,132
Cash Held in Collective Trust Funds	27,471	—	—	—	27,471
Total Retirement Plan Investments	1,202,803	1,593	772,190	319	428,701
401(h) Investments	(90,429)	(121)	(58,840)	(24)	(31,444)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 1,112,374	$ 1,472	$ 713,350	$ 295	$ 397,257
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(16,645)				
Total Retirement Plan Assets	$ 1,095,729				

(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).

	At September 30, 2022				
	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	$ 104,554	$ —	$ —	$ —	$ 104,554
Exchange Traded Funds — Fixed Income	270,581	270,581	—	—	—
Cash Held in Collective Trust Funds	10,635	—	—	—	10,635
Total VEBA Trust Investments	385,770	270,581	—	—	115,189
401(h) Investments	73,044	3,310	46,694	—	23,040
Total Investments (including 401(h) Investments)	$ 458,814	$ 273,891	$ 46,694	$ —	$ 138,229
Miscellaneous Accruals (including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	2,624				
Total Other Post-Retirement Benefit Assets	$ 461,438				

	At September 30, 2021				
	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	$ 165,226	$ —	$ —	$ —	$165,226
Exchange Traded Funds — Fixed Income	313,392	313,392	—	—	—
Cash Held in Collective Trust Funds	9,700	—	—	—	9,700
Total VEBA Trust Investments	488,318	313,392	—	—	174,926
401(h) Investments	90,429	121	58,840	24	31,444
Total Investments (including 401(h) Investments)	$ 578,747	$ 313,513	$ 58,840	$ 24	$206,370
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(3,182)				
Total Other Post-Retirement Benefit Assets	$ 575,565				

(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, 2022 and September 30, 2021, 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.

	Retirement Plan Level 3 Assets (Thousands)		
	Real Estate	Excluding 401(h) Investments	Total
Balance at September 30, 2020	$ 471	$ (35)	$ 436
Unrealized Gains/(Losses)	(152)	11	(141)
Sales	—	—	—
Balance at September 30, 2021	319	(24)	295
Unrealized Gains/(Losses)	234	(18)	216
Sales	(553)	42	(511)
Balance at September 30, 2022	$ —	$ —	$ —

	Other Post-Retirement Benefit Level 3 Assets (Thousands)
	401(h) Investments
Balance at September 30, 2020	$ 35
Unrealized Gains/(Losses)	(11)
Sales	—
Balance at September 30, 2021	24
Unrealized Gains/(Losses)	18
Sales	(42)
Balance at September 30, 2022	$ —

The Company's assumption regarding the expected long-term rate of return on plan assets is 6.90% (Retirement Plan) and 5.70% (other post-retirement benefits), effective for fiscal 2023. 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). Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trust, 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. In fiscal 2021 and fiscal 2022, capital market conditions led to significant improvements in the funded status of the Retirement Plan. As a result, the Company reduced the return seeking portion of its assets during both years, particularly equity securities and return seeking fixed income securities, held in the Retirement Plan, and increased its allocation to hedging fixed income securities in conjunction with the Company's liability driven investment strategy. The actual asset allocations as of September 30, 2022 are noted in the table above, and such allocations are subject to change, but the majority of the assets will remain hedging fixed income assets. Given the level of the VEBA trust and 401(h) assets in relation to the Other Post-Retirement Benefits, the majority of those assets are and will remain in fixed income securities.

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 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, 2022, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately $3.6 million. The Company's liability for such clean-up costs has been recorded in Other Liabilities on the Consolidated Balance Sheet at September 30, 2022. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately one year and is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could have an adverse financial impact on the Company.

Northern Access Project

On February 3, 2017, Supply Corporation and Empire received FERC approval of the Northern Access project described herein. Shortly thereafter, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received in January of 2017). Subsequently, FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. FERC denied rehearing requests associated with its Order and FERC's decisions were appealed. The Second Circuit Court of Appeals issued an order upholding the FERC waiver orders. In addition, in the Company's state court litigation challenging the NYDEC's actions with regard to various state permits, the New York State Supreme Court issued a decision finding these permits to be preempted. The Company remains committed to the project and, on June 29, 2022, received an extension of time from FERC, until December 31, 2024, to construct the project. As of September 30, 2022, the Company has spent approximately $55.8 million on the project, all of which is recorded on the balance sheet.

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: $458.2 million in 2023, $98.6 million in 2024, $135.6 million in 2025, $150.7 million in 2026, $142.1 million in 2027 and $1,001.0 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 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, 2022, the future contractual commitments related to the system modernization and expansion projects are $68.9 million in 2023, $8.5 million in 2024, $8.1 million in 2025, $6.9 million in 2026, $5.8 million in 2027 and $5.8 million thereafter.

The Company, in its Exploration and Production segment, has entered into contractual obligations to support its development activities and operations in Pennsylvania, including hydraulic fracturing and other well completion services, well tending services, well workover activities, tubing and casing purchases, production equipment purchases, water hauling services and contracts for drilling rig services. The future contractual commitments are $282.5 million in 2023, $180.4 million in 2024 and $153.8 million in 2025, and $43.8 million in 2026. There are no contractual commitments extending beyond 2026.

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 reserves in the Appalachian region of the United States.

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 primarily 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 — 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, 2022							
	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)(2)	$ 1,010,464	$ 265,415	$ 12,086	$ 897,916	$ 2,185,881	$ —	$ 165	$ 2,186,046
Intersegment Revenues	$ —	$ 111,629	$ 202,757	$ 305	$ 314,691	$ 6	$ (314,697)	$ —
Interest Income	$ 1,929	$ 2,275	$ 198	$ 2,730	$ 7,132	$ 3	$ (1,024)	$ 6,111
Interest Expense	$ 53,401	$ 42,492	$ 16,488	$ 24,115	$ 136,496	$ 4	$ (6,143)	$ 130,357
Depreciation, Depletion and Amortization	$ 208,148	$ 67,701	$ 33,998	$ 59,760	$ 369,607	$ —	$ 183	$ 369,790
Income Tax Expense (Benefit)	$ 43,898	$ 35,043	$ 24,949	$ 17,165	$ 121,055	$ 3	$ (4,429)	$ 116,629
Significant Item: Gain on Sale of Assets	$ 12,736	$ —	$ —	$ —	$ 12,736	$ —	$ —	$ 12,736
Segment Profit: Net Income (Loss)	$ 306,064	$ 102,557	$ 101,111	$ 68,948	$ 578,680	$ (9)	$ (12,650)	$ 566,021
Expenditures for Additions to Long-Lived Assets	$ 565,791	$ 95,806	$ 55,546	$ 111,033	$ 828,176	$ —	$ 1,212	$ 829,388
	At September 30, 2022							
	(Thousands)							
Segment Assets	$ 2,507,541	$2,394,697	$ 878,796	$2,299,473	$ 8,080,507	$ 2,036	$ (186,281)	$ 7,896,262

	Year Ended September 30, 2021							
	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)	$ 836,697	$ 234,397	$ 3,116	$ 666,920	$ 1,741,130	$ 1,173	$ 356	$ 1,742,659
Intersegment Revenues	$ —	$ 109,160	$ 190,148	$ 331	$ 299,639	$ 49	$ (299,688)	$ —
Interest Income	$ 211	$ 1,085	$ 259	$ 2,117	$ 3,672	$ 230	$ 486	$ 4,388
Interest Expense	$ 69,662	$ 40,976	$ 17,493	$ 21,795	$ 149,926	$ —	$ (3,569)	$ 146,357
Depreciation, Depletion and Amortization	$ 182,492	$ 62,431	$ 32,350	$ 57,457	$ 334,730	$ 394	$ 179	$ 335,303
Income Tax Expense (Benefit)	$ 33,370	$ 28,812	$ 28,876	$ 14,007	$ 105,065	$ 11,438	$ (1,821)	$ 114,682
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	$ 76,152	$ —	$ —	$ —	$ 76,152	$ —	$ —	$ 76,152
Significant Item: Gain on Sale of Assets	$ —	$ —	$ —	$ —	$ —	$ 51,066	$ —	$ 51,066
Segment Profit: Net Income (Loss)	$ 101,916	$ 92,542	$ 80,274	$ 54,335	$ 329,067	$ 37,645	$ (3,065)	$ 363,647
Expenditures for Additions to Long-Lived Assets	$ 381,408	$ 252,316	$ 34,669	$ 100,845	$ 769,238	$ —	$ 673	$ 769,911
	At September 30, 2021							
	(Thousands)							
Segment Assets	$ 2,286,058	$2,296,030	$ 837,729	$2,148,267	$ 7,568,084	$ 4,146	$ (107,405)	$ 7,464,825

	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

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

(2) Revenues from three customers of the Company's Exploration and Production segment, exclusive of hedging losses transacted with separate parties, represented approximately $850 million of the Company's consolidated revenue for the year ended September 30, 2022. These three customers were also customers of the Company's Pipeline and Storage segment, accounting for an additional $15 million of the Company's consolidated revenue for the year ended September 30, 2022.

Geographic Information	At September 30		
	2022	2021	2020
	(Thousands)		
Long-Lived Assets:			
United States	$ 7,135,131	$ 6,942,376	$ 6,597,313

Note N — 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 authoritative guidance. All monetary amounts are expressed in U.S. dollars. As discussed in Note B — Asset Acquisitions and Divestitures, the Company completed the sale of its California assets on June 30, 2022. With the completion of this sale, the Company no longer has any oil or gas reserves in the West Coast region of the U.S.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30 2022	At September 30 2021
	(Thousands)	
Proved Properties(1)	$ 5,915,807	$ 6,652,341
Unproved Properties	65,994	103,759
	5,981,801	6,756,100
Less — Accumulated Depreciation, Depletion and Amortization	4,034,266	4,881,972
	$ 1,947,535	$ 1,874,128

(1) Includes asset retirement costs of $120.8 million and $152.8 million at September 30, 2022 and 2021, 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 2027. It expects the majority of its development and exploration costs associated with unproved properties to be transferred into the amortization base by 2025. Following is a summary of costs excluded from amortization at September 30, 2022:

	Total as of September 30, 2022	Year Costs Incurred 2022	2021	2020	Prior
			(Thousands)		
Acquisition Costs	$ 41,831	$ —	$ —	$ 29,698	$ 12,133
Development Costs	24,163	17,590	4,085	2,488	—
Exploration Costs	—	—	—	—	—
Capitalized Interest	—	—	—	—	—
	$ 65,994	$ 17,590	$ 4,085	$ 32,186	$ 12,133

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

	Year Ended September 30 2022	2021	2020
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ 2,491	$ 1,801	$ 245,976
Unproved	10,665	5,102	42,922
Exploration Costs(1)	9,631	15,413	3,891
Development Costs(2)	528,684	329,368	355,742
Asset Retirement Costs	9,768	20,194	62,080
	$ 561,239	$ 371,878	$ 710,611

(1) Amounts for 2022, 2021 and 2020 include capitalized interest of zero, $0.1 million and zero respectively.
(2) Amounts for 2022, 2021 and 2020 include capitalized interest of $0.6 million, $0.4 million and $1.0 million, respectively.

For the years ended September 30, 2022, 2021 and 2020, the Company spent $154.3 million, $81.2 million and $219.9 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2022	2021	2020
United States	(Thousands, except per Mcfe amounts)		
Operating Revenues:			
Gas (includes transfers to operations of $5,696, $3,061 and $1,921, respectively)(1)	$ 1,730,723	$ 780,477	$ 402,447
Oil, Condensate and Other Liquids	150,957	135,191	107,844
Total Operating Revenues(2)	1,881,680	915,668	510,291
Production/Lifting Costs	283,914	267,316	203,670
Franchise/Ad Valorem Taxes	25,112	22,128	15,582
Purchased Emission Allowance Expense	1,305	2,940	2,930
Accretion Expense	7,530	7,743	5,237
Depreciation, Depletion and Amortization ($0.57, $0.54 and $0.69 per Mcfe of production, respectively)	202,418	177,055	166,759
Impairment of Oil and Gas Producing Properties	—	76,152	449,438
Income Tax Expense	368,925	98,593	(92,820)
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$ 992,476	$ 263,741	$ (240,505)

(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.

Reserve Quantity Information

The Company's proved oil and gas reserve estimates are prepared by the Company's petroleum 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 Senior Manager 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 13 years of Petroleum Engineering experience with independent oil and gas companies, licensure as a Professional Engineer and is a member of the Society of Petroleum Engineers.

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 Senior Manager 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 & 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, 2022 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.

	Gas MMcf			
	U.S.			
	Appalachian Region		West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
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
Extensions and Discoveries	689,395	(1)	—	689,395
Revisions of Previous Estimates	19,940		3,033	22,973
Production	(312,300)	(2)	(1,720)	(314,020)
September 30, 2021	3,693,148		30,285	3,723,433
Extensions and Discoveries	837,510	(1)	—	837,510
Revisions of Previous Estimates	2,882		71	2,953
Production	(341,700)	(2)	(1,211)	(342,911)
Sale of Minerals in Place	(21,178)		(29,145)	(50,323)
September 30, 2022	4,170,662		—	4,170,662
Proved Developed Reserves:				
September 30, 2019	1,901,162		33,633	1,934,795
September 30, 2020	2,744,851		28,972	2,773,823
September 30, 2021	3,061,178		30,285	3,091,463
September 30, 2022	3,312,568		—	3,312,568
Proved Undeveloped Reserves:				
September 30, 2019	1,014,724		—	1,014,724
September 30, 2020	551,262		—	551,262
September 30, 2021	631,970		—	631,970
September 30, 2022	858,094		—	858,094

(1) Extensions and discoveries include 7 Bcf (during 2020), 180 Bcf (during 2021) and 301 Bcf (during 2022), of Marcellus Shale gas (which exceed 15% of total reserves) in the Appalachian region. Extensions and discoveries include 0 Bcf (during 2020), 497 Bcf (during 2021) and 537 Bcf (during 2022), of Utica Shale gas (which exceed 15% of total reserves) in the Appalachian region.

(2) Production includes 169,453 MMcf (during 2020), 218,016 MMcf (during 2021) and 209,463 MMcf (during 2022), from Marcellus Shale fields. Production includes 55,392 MMcf (during 2020), 93,253 MMcf (during 2021) and 130,240 MMcf (during 2022), from Utica Shale fields.

	Oil Mbbl		
	U.S.		
	Appalachian Region	West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:			
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
Extensions and Discoveries	—	1,041	1,041
Revisions of Previous Estimates	1	630	631
Production	(2)	(2,233)	(2,235)
September 30, 2021	11	21,526	21,537
Extensions and Discoveries	—	296	296
Revisions of Previous Estimates	255	532	787
Production	(16)	(1,588)	(1,604)
Sales of Minerals in Place	—	(20,766)	(20,766)
September 30, 2022	250	—	250
Proved Developed Reserves:			
September 30, 2019	13	24,246	24,259
September 30, 2020	12	22,088	22,100
September 30, 2021	11	20,930	20,941
September 30, 2022	250	—	250
Proved Undeveloped Reserves:			
September 30, 2019	—	614	614
September 30, 2020	—	—	—
September 30, 2021	—	596	596
September 30, 2022	—	—	—

The Company’s proved undeveloped (PUD) reserves increased from 636 Bcfe at September 30, 2021 to 858 Bcfe at September 30, 2022. PUD reserves in the Utica Shale increased from 411 Bcfe at September 30, 2021 to 503 Bcfe at September 30, 2022. PUD reserves in the Marcellus Shale increased from 220 Bcfe at September 30, 2021 to 355 Bcfe at September 30, 2022. PUD reserves in the West Coast region decreased from 5 Bcfe at September 30, 2021 to zero at September 30, 2022. The Company’s total PUD reserves were 20.6% of total proved reserves at September 30, 2022, up from 16.5% of total proved reserves at September 30, 2021.

The Company’s PUD reserves increased from 551 Bcfe at September 30, 2020 to 636 Bcfe at September 30, 2021. PUD reserves in the Utica Shale increased from 265 Bcfe at September 30, 2020 to 411 Bcfe at September 30, 2021. PUD reserves in the Marcellus Shale decreased from 287 Bcfe at September 30, 2020 to 220 Bcfe at September 30, 2021. The Company’s total PUD reserves were 16.5% of total proved reserves at September 30, 2021, roughly flat from 16% of total proved reserves at September 30, 2020.

The increase in PUD reserves in 2022 of 222 Bcfe is a result of 502 Bcfe in new PUD reserve additions and 23 Bcfe in upward revisions to remaining PUD reserves, partially offset by 287 Bcfe in PUD conversions to developed reserves (55 Bcfe from the Marcellus Shale, 231 Bcfe from the Utica Shale and 1 Bcfe from the West Coast region), and 13 Bcfe in PUD reserves removed for one Utica PUD location due to pad layout changes. The remaining change of 3 Bcf was due to removing West Coast region PUDs included in the beginning of year balances through development and divesture of Seneca's California assets.

The increase in PUD reserves in 2021 of 85 Bcfe is a result of 344 Bcfe in new PUD reserve additions and 9 Bcfe in upward revisions to remaining PUD reserves, partially offset by 188 Bcfe in PUD conversions to developed reserves (82 Bcfe from the Marcellus Shale and 106 Bcfe from the Utica Shale), and 80 Bcfe in PUD reserves removed for eight PUD locations, half of these due to pad layout changes, and the other half due to schedule changes. Six of these wells removed were in the Marcellus Shale (54 Bcfe) and two were in the Utica Shale (26 Bcfe).

The Company invested $154 million during the year ended September 30, 2022 to convert 287 Bcfe (333 Bcfe after revisions) of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 45% of the net PUD reserves recorded at September 30, 2021. In the Appalachian region, 31 of 65 PUD locations were developed while the West Coast region developed 6 of 17 PUD locations prior to the divesture. PUD expenditures in 2022 were lower than the 2021 estimate primarily due to changes in the development schedule.

The Company invested $81 million during the year ended September 30, 2021 to convert 188 Bcfe (198 Bcfe after revisions) of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 34% of the net PUD reserves recorded at September 30, 2020. In the Appalachian region, 18 of 53 PUD locations were developed. PUD expenditures in 2021 were lower than the 2020 estimate primarily due to changes in the development schedule.

In 2023, the Company estimates that it will invest approximately $308 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 was adopted, and over the last five years, the Company developed 51% of its beginning year PUD reserves in fiscal 2018, 39% of its beginning year PUD reserves in fiscal 2019, 36% of its beginning year PUD reserves in fiscal 2020, 34% of its beginning year PUD reserves in fiscal 2021 and 45% of its beginning year PUD reserves in fiscal 2022.

At September 30, 2022, 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.

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
United States			
Future Cash Inflows	$19,209,099	$10,175,182	$ 6,493,362
Less:			
Future Production Costs	3,138,226	3,423,629	3,149,857
Future Development Costs	781,847	597,662	501,678
Future Income Tax Expense at Applicable Statutory Rate	3,876,272	1,397,175	454,553
Future Net Cash Flows	11,412,754	4,756,716	2,387,274
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	5,964,424	2,403,144	1,164,804
Standardized Measure of Discounted Future Net Cash Flows	$ 5,448,330	$ 2,353,572	$ 1,222,470

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

	Year Ended September 30		
	2022	2021	2020
		(Thousands)	
United States			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	$ 2,353,572	$ 1,222,470	$ 1,736,319
Sales, Net of Production Costs	(1,572,402)	(626,132)	(290,975)
Net Changes in Prices, Net of Production Costs	4,132,889	1,478,995	(1,109,101)
Extensions and Discoveries	1,355,257	462,040	4,236
Changes in Estimated Future Development Costs	(32,160)	48,247	99,884
Purchases of Minerals in Place	—	—	170,363
Sales of Minerals in Place	(311,308)	—	—
Previously Estimated Development Costs Incurred	154,253	81,239	219,938
Net Change in Income Taxes at Applicable Statutory Rate	(1,180,349)	(415,993)	248,182
Revisions of Previous Quantity Estimates	3,316	(52,383)	(28,337)
Accretion of Discount and Other	545,262	155,089	171,961
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$ 5,448,330	$ 2,353,572	$ 1,222,470

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, 2022.

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, 2022. 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, 2022.

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, 2022. 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, 2022 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Item 9B ***Other Information***

None.

Item 9C ***Disclosure Regarding Foreign Jurisdictions that Prevent Inspections***

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, 2022. The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled “Nominees for Election as Directors for One-Year Terms to Expire in 2024,” and

“Continuing Directors Whose Terms Expire in 2024,” 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 will be 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

All schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes 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:
•	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)
•	Certificate of Amendment of Restated Certificate of Incorporation, as amended, of National Fuel Gas Company (Exhibit 3.1, Form 8-K dated March 16, 2021)
3(ii)	By-Laws:
•	By-Laws of National Fuel Gas Company, as amended June 15, 2022 (Exhibit 3.1, Form 8-K dated June 17, 2022)
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)

Exhibit Number	Description of Exhibits
•	Officers Certificate establishing 3.75% Notes due 2023, dated February 15, 2023 (Exhibit 4.1.1, Form 8-K dated February 15, 2013)
•	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)
•	Officer’s Certificate establishing 2.95% Notes due 2031, dated February 24, 2021 (Exhibit 4.1.1, Form 8-K dated February 24, 2021)
10	Material Contracts:
•	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)
•	Credit Agreement, dated as of February 28, 2022, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent (Exhibit 10.1, Form 8-K dated February 28, 2022)
•	Amendment No. 1 to Credit Agreement, dated as of May 3, 2022, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A. as Administrative Agent (Exhibit 10.1, Form 10-Q dated May 6, 2022)
•	364-Day Credit Agreement, dated as of June 30, 2022, among the Company, the Lenders party thereto, and Wells Fargo Bank, National Association as Administrative Agent (Exhibit 10.1, Form 8-K dated July 1, 2022)
10.1	Amendment No. 1 to 364-Day Credit Agreement, dated as of September 27, 2022, among the Company, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent
	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)
•	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)

Exhibit Number	**Description of Exhibits**
•	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)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated December 14, 2020 (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2020)
•	National Fuel Gas Company Deferred Compensation Plan for Directors and Officers (Amended and Restated Effective September 1, 2021) (Exhibit 10.1, Form 8-K dated June 23, 2021)
•	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)
•	Amendment to National Fuel Gas Company Tophat Plan, dated December 14, 2020 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2020)
•	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)

Exhibit Number	Description of Exhibits
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 14, 2020 (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2020)
•	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, 2021)
•	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, 2021)
•	Form of Award Notice for ESG Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2021)
•	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, 2020)
•	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, 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)
21	Subsidiaries of the Registrant
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

Exhibit Number	Description of Exhibits
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, 2022, 2021 and 2020, (ii) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2022, 2021 and 2020 (iii) the Consolidated Balance Sheets at September 30, 2022 and September 30, 2021, (iv) the Consolidated Statements of Cash Flows for the years ended September 30, 2022, 2021 and 2020 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.

Item 16 *Form 10-K Summary*

None.

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 18, 2022

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	
/s/ D. F. Smith D. F. Smith	Chairman of the Board and Director	Date: November 18, 2022
/s/ D. H. Anderson D. H. Anderson	Director	Date: November 18, 2022
/s/ B. M. Baumann B. M. Baumann	Director	Date: November 18, 2022
/s/ D. C. Carroll D. C. Carroll	Director	Date: November 18, 2022
/s/ S. C. Finch S.C. Finch	Director	Date: November 18, 2022
/s/ J. N. Jaggers J. N. Jaggers	Director	Date: November 18, 2022
/s/ R. Ranich R. Ranich	Director	Date: November 18, 2022
/s/ J. W. Shaw J. W. Shaw	Director	Date: November 18, 2022
/s/ T. E. Skains T. E. Skains	Director	Date: November 18, 2022
/s/ R. J. Tanski R. J. Tanski	Director	Date: November 18, 2022
/s/ D. P. Bauer D. P. Bauer	President and Chief Executive Officer and Director	Date: November 18, 2022
/s/ K. M. Camiolo K. M. Camiolo	Treasurer and Principal Financial Officer	Date: November 18, 2022
/s/ E. G. Mendel E. G. Mendel	Controller and Principal Accounting Officer	Date: November 18, 2022

Investor Information

Common Stock Transfer Agent and Registrar

EQ Shareowner Services
P.O. Box 64854
St. Paul, MN 55164-0854
Telephone: 800-648-8166
Web: http://www.shareowneronline.com
Email: stocktransfer@equiniti.com

Change of address notices and inquiries about dividends should be sent to the Transfer Agent at the address listed above.

National Fuel Direct Stock Purchase and Dividend Reinvestment Plan

National Fuel offers a simple, cost-effective method for purchasing shares of National Fuel stock. A prospectus, which includes details of the Plan, can be obtained by calling, writing or emailing the administrator of the Plan, EQ Shareowner Services, at the address listed above.

Investor Relations

Investors or financial analysts desiring information should contact:

Karen M. Camiolo, Treasurer
Telephone: 716-857-7344

Brandon J. Haspett,
Director of Investor Relations
Telephone: 716-857-7697
Email: HaspettB@natfuel.com

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Additional Shareholder Reports

Additional copies of this report, the 2022 Form 10-K and the 2022 Financial and Statistical Report can be obtained without charge by writing to or calling:

Sarah J. Mugel, Corporate Secretary
Telephone: 716-857-7163

Brandon J. Haspett,
Director of Investor Relations
Telephone: 716-857-7697

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Stock Exchange Listing

New York Stock Exchange
(Stock Symbol: NFG)

Trustee for Debentures

The Bank of New York Mellon
Corporate Trust
240 Greenwich Street, 7 East
New York, NY 10286

Annual Meeting

The Annual Meeting of Stockholders will be held on Thursday, March 9, 2023 conducted via live webcast at www.virtualshareholdermeeting.com/NFG2023. Stockholders of record as of the close of business on January 9, 2023, will receive a formal notice of the meeting, proxy statement, and proxy.

Units of Measure

Bbl	Barrel *(of oil)*
Bcf	Billion cubic feet *(of natural gas)*
Bcfe	Bcf equivalent *(of natural gas and oil)*
Dth	Dekatherm (*approx. 1 Mcf of natural gas)*
Mbbl	Thousand barrels (of oil)
Mcf	Thousand cubic feet *(of natural gas)*
Mcfe	Mcf equivalent *(of natural gas and oil)*
MMcf	Million cubic feet *(of natural gas)*
MMcfe	Million cubic feet equivalent

Design by addison.com

Revegetated FM100 right of way in Elk State Forest in PA. Supply will plant additional trees on this portion of right of way as part of its reclamation efforts.

National Fuel®

National Fuel Gas Company
6363 Main Street
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716-857-7000
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NYSE: NFG