NATIONAL FUEL GAS CO
Form 10-K
November 16, 2018

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
Form 10-K
þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended September 30, 2018
¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Transition Period from to
Commission File Number 1-3880
National Fuel Gas Company
(Exact name of registrant as specified in its charter)

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

(716) 857-7000
Registrant's telephone number, including area code
Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $1.00 per share, and Common Stock Purchase Rights	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 þ 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 þ
Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months and (2) has been subject to such filing requirements for the past 90 days. Yes þ No ¨
Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes þ No ¨
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. þ
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. (Check one):

Large accelerated filer þ	Accelerated filer ¨
Non-accelerated filer ¨	Smaller reporting company ¨
Emerging growth company ¨	

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

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

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $4,333,193,000 as of March 31, 2018.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2018: 85,963,834 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2019 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2018, 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 (formerly National Fuel Gas Midstream Corporation) *
National Fuel National Fuel Gas Company
NFR National Fuel Resources, Inc.
Registrant National Fuel Gas Company
Seneca Seneca Resources Company, LLC (formerly Seneca Resources Corporation) *
Supply Corporation National Fuel Gas Supply Corporation
* Effective August 1, 2018, the Company converted Seneca Resources Corporation and National Fuel Gas Midstream Corporation to limited liability companies (LLCs) for tax purposes. Both LLCs are wholly owned by a newly formed subsidiary named Pennsylvania Gas Holdings Corporation which in turn is wholly owned by the Company.
Regulatory Agencies
CFTC Commodity Futures Trading Commission
EPA United States Environmental Protection Agency
FASB Financial Accounting Standards Board
FERC Federal Energy Regulatory Commission
NYDEC New York State Department of Environmental Conservation
NYPSC State of New York Public Service Commission
PaDEP Pennsylvania Department of Environmental Protection
PaPUC Pennsylvania Public Utility Commission
PHMSA Pipeline and Hazardous Materials Safety Administration
SEC Securities and Exchange Commission
Other
2017 Tax Reform Act Tax legislation referred to as the "Tax Cuts and Jobs Act," enacted December 22, 2017.
Bbl Barrel (of oil)
Bcf Billion cubic feet (of natural gas)
Bcfe (or Mcfe) — represents Bcf (or Mcf) Equivalent The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.
Btu British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.
Capital expenditure Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
Cashout revenues A cash resolution of a gas imbalance whereby a customer pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation’s and Empire’s systems by the customer’s shipper.
Degree day A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or

contract. Examples include futures contracts, options, no cost collars and swaps.
Development costs Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.
Development well A well drilled to a known producing formation in a previously discovered field.
Dodd-Frank Act Dodd-Frank Wall Street Reform and Consumer Protection Act.
Dth Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploitation Development of a field, including the location, drilling, completion and equipment of wells necessary to produce the commercially recoverable oil and gas in the field.
Exploration costs Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
FERC 7(c) application An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.
Exploratory well A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.
Firm transportation and/or storage The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.
GAAP Accounting principles generally accepted in the United States of America
Goodwill An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.
Hedging A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.
Hub Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.
ICE Intercontinental Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Interruptible transportation and/or storage The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.
LDC Local distribution company
LIBOR London Interbank Offered Rate
LIFO Last-in, first-out
Marcellus Shale A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.
Mbbl Thousand barrels (of oil)
Mcf Thousand cubic feet (of natural gas)
MD&A Management's Discussion and Analysis of Financial Condition and Results of Operations
MDth Thousand decatherms (of natural gas)
MMBtu Million British thermal units (heating value of one dekatherm of natural gas)
MMcf Million cubic feet (of natural gas)
MMcfe Million cubic feet equivalent
NEPA National Environmental Policy Act of 1969, as amended

NGA The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
NYMEX New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Open Season A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
PCB Polychlorinated Biphenyl
Precedent Agreement An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called “conditions precedent”) happen, usually within a specified time.
Proved developed reserves Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make those reserves productive.
PRP Potentially responsible party
Reliable technology Technology that a company may use to establish reserves estimates and categories that has been proven empirically to lead to correct conclusions.
Reserves The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Restructuring Generally referring to partial “deregulation” of the pipeline and/or utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or “unbundling”) of gas commodity service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.

Revenue decoupling mechanism A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.

S&P Standard & Poor’s Ratings Service
SAR Stock appreciation right
Service Agreement The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
Spot gas purchases The purchase of natural gas on a short-term basis.
Stock acquisitions Investments in corporations.
Unbundled service A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
Utica Shale A Middle Ordovician-age geological formation lying several thousand feet below the Marcellus Shale in the Appalachian region of the United States, including much of Ohio, Pennsylvania, West Virginia and southern New York.
VEBA Voluntary Employees’ Beneficiary Association
WNC Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

For the Fiscal Year Ended September 30, 2018

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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. Except as otherwise indicated below, 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, distribution and marketing 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 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. The common geographic footprint of the Company’s subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian basin to markets in Canada and the eastern United States. The Company also develops and produces oil reserves, primarily in California. The Company reports financial results for five business segments: Exploration and Production, Pipeline and Storage, Gathering, Utility, and Energy Marketing.

1. The Exploration and Production segment operations are carried out by Seneca Resources Company, LLC (Seneca), a Pennsylvania limited liability company. Seneca is engaged in the exploration for, and the development and production of, natural gas and oil reserves in California and in the Appalachian region of the United States. At September 30, 2018, Seneca had U.S. proved developed and undeveloped reserves of 27,663 Mbbl of oil and 2,357,342 MMcf of natural gas.

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 provides interstate natural gas transportation and storage services for affiliated and nonaffiliated companies through (i) an integrated gas pipeline system extending from southwestern Pennsylvania to the New York-Canadian border at the Niagara River and eastward to Ellisburg and Leidy, Pennsylvania, and (ii) 28 underground natural gas storage fields owned and operated by Supply Corporation as well as three other underground natural gas storage fields owned and operated jointly with other interstate gas pipeline companies. 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 along with exploration and production companies from natural gas producing areas in Pennsylvania to markets in New York and to interstate pipeline delivery points for additional markets in the northeastern United States and Canada. Empire owns the Empire Pipeline, a 266-mile pipeline system comprising four principal components: a 157-mile pipeline that extends from the United States/Canadian border at the Niagara River near Buffalo, New York to near Syracuse, New York; a 77-mile pipeline extension from near Rochester, New York to an interconnection with the unaffiliated Millennium Pipeline near Corning, New York (the Empire Connector), a 15-mile pipeline extension from Corning into Tioga County, Pennsylvania (the Tioga County Extension) and a 17-mile pipeline extension between Empire's pipeline system and Supply Corporation's system at Tuscarora, New York.

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 sells natural gas or provides natural gas

transportation services to approximately 750,200 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.
5. The Energy Marketing segment operations are carried out by National Fuel Resources, Inc. (NFR), a New York corporation, which markets natural gas to industrial, wholesale, commercial, public authority and residential customers primarily in western and central New York and northwestern Pennsylvania, offering competitively priced natural gas for its customers.

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 J — Business Segment Information.

Seneca’s Northeast Division is included in the Company's All Other Category. This division markets timber from Appalachian land holdings. At September 30, 2018, the Company owned approximately 94,000 acres of timber property and managed approximately 3,000 additional acres of timber cutting rights.

No single customer, or group of customers under common control, accounted for more than 10% of the Company’s consolidated revenues in 2018.

Rates and Regulation

The Utility segment’s rates, services and other matters are regulated by the NYPSC with respect to services provided within New York and by the PaPUC with respect to services provided within Pennsylvania. For additional discussion of the Utility segment’s rates and regulation, see Item 7, MD&A under the heading “Rate and Regulatory Matters” and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note C — Regulatory Matters.

The Pipeline and Storage segment’s rates, services and other matters are regulated by the FERC. For additional discussion of the Pipeline and Storage segment’s rates and regulation, see Item 7, MD&A under the heading “Rate and Regulatory Matters” and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note C — Regulatory Matters.

The discussion under Item 8 at Note C — 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.

In addition, the Company and its subsidiaries are subject to the same federal, state and local regulations on various subjects, including environmental matters, to which other companies doing similar business in the same locations are subject.

The Exploration and Production Segment

The Exploration and Production segment contributed approximately 46.1% of the Company's 2018 net income available for common stock.

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 approximately 24.8% of the Company's 2018 net income available for common stock.

Supply Corporation’s firm transportation capacity is subject to change as the market identifies different transportation paths and receipt/delivery point combinations. At the end of fiscal year 2018, Supply Corporation had firm transportation service agreements and leases for approximately 3,187 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,124 MDth per day or 35% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 165 MDth per day or 5%. Additionally, Supply Corporation leases 55 MDth per day or 2% of its firm transportation capacity to Empire. The remaining 1,843 MDth or 58% is subject to firm contracts or leases with nonaffiliated customers. Contracted transportation capacity with both affiliated and nonaffiliated shippers is expected to remain relatively constant in fiscal 2019.

Supply Corporation had service agreements and leases for all of its firm storage capacity, totaling 71,938 MDth, at the end of 2018. The Utility segment has contracted for 28,491 MDth or 40% of the total firm storage capacity, and the Energy Marketing segment accounts for another 2,644 MDth or 4%. Additionally, Supply Corporation leases 3,753 MDth or 5% of its firm storage capacity to Empire. Nonaffiliated customers have contracted for the remaining 37,050 MDth or 51%. Supply Corporation expects several contracted storage services to terminate and be remarketed in fiscal 2019 totaling approximately 2,000 MDth.

At the end of fiscal 2018, Empire had service agreements in place for firm transportation capacity totaling up to approximately 978 MDth per day, with 95% of that capacity contracted as long-term, full-year deals. The Utility segment accounted for 4% of Empire’s firm contracted capacity, with the remaining 96% subject to contracts with nonaffiliated customers. Empire expects several contracted firm transportation services to terminate and be remarketed in fiscal 2019 totaling approximately 153 MDth per day.

Empire’s firm storage capacity, totaling 3,753 MDth, was fully contracted at the end of fiscal 2018. The total storage capacity is contracted on a long-term basis, with a nonaffiliated customer. The contract will not expire or terminate in fiscal 2019.

The majority of Supply Corporation’s transportation and storage contracts, and the majority of Empire’s transportation 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). Empire's storage contract contains similar termination and "evergreen" language.

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 approximately 21.3% of the Company's 2018 net income available for common stock.

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 approximately 13.1% of the Company's 2018 net income available for common stock.

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.

The Energy Marketing Segment

The Energy Marketing segment contributed approximately 0.1% of the Company's 2018 net income available for common stock.

Additional discussion of the Energy Marketing segment appears below under the headings “Sources and Availability of Raw Materials,” “Competition: The Energy Marketing 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 in 2018. The impact of this net loss in relation to the Company's 2018 net income available for common stock was negative 5.4%.

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

Sources and Availability of Raw Materials

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

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

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

Natural gas is the principal raw material for the Utility segment. In 2018, the Utility segment purchased 74.5 Bcf of gas (including 70.0 Bcf for delivery to retail customers, 0.1 Bcf for off-system sales and 4.4 Bcf used in operations). Gas purchased from producers and suppliers in the United States under firm contracts (seasonal and longer) accounted for 52% of these purchases. Purchases of gas on the spot market (contracts of one month or less) accounted for 48% of the Utility segment’s 2018 purchases. Purchases from DTE Energy Trading, Inc. (31%), NextEra Energy Marketing, LLC (12%), SWN Energy Services Company, LLC (11%), South Jersey Resources Group, LLC (10%), Shell Energy North America US (7%) and Direct Energy Business Marketing (5%) accounted for 76% of the Utility’s 2018 gas purchases. No other producer or supplier provided the Utility segment with more than 5% of its gas requirements in 2018.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2018, this segment purchased 42.8 Bcf of gas, including 42.3 Bcf for delivery to its customers. The remaining 0.5 Bcf largely represents gas used in operations. The gas purchased by the Energy Marketing segment originates primarily in either the Appalachian or mid-continent regions of the United States.

Competition

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

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

Competition: The Exploration and Production Segment

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

To compete in this environment, Seneca originates and acts 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 market niches 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, as described below. Most of Supply Corporation's facilities are in or near areas overlying the Marcellus and Utica Shale production areas in Pennsylvania, and it has established interconnections with producers and other pipelines to access these supplies. Its facilities are also located adjacent to the Canadian border at the Niagara River providing access to markets in Canada and, through TransCanada Pipeline, to markets in the northeastern and midwestern United States. Supply Corporation has developed and placed into service a number of pipeline expansion projects to transport natural gas to key markets within New York and Pennsylvania, the northeastern United States, Canada, and most recently to long-haul pipelines moving gas into the U.S. Midwest and even back to the gulf coast. For further discussion of Pipeline and Storage projects, refer to Item 7, MD&A under the headings "Investing Cash Flow."

Empire competes for market growth in the natural gas market 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-sourced gas as well as gas received at the Niagara River at Chippawa. Empire's location provides it the opportunity to compete for an increased share of the gas transportation markets both for delivery to the New York and Northeast markets and from and into Canada. The Empire Connector and other projects expanded Empire's natural gas pipeline and enables 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 Marcellus Shale 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's production and competes with other companies that gather and process natural gas in the Appalachian region.

Competition: The Utility Segment

With respect to gas commodity service, in New York and Pennsylvania, both of which have implemented "unbundling" policies that allow customers to choose their gas commodity supplier, Distribution Corporation has retained a substantial majority of small sales customers. In New York, approximately 17%, and in Pennsylvania, approximately 14%, of Distribution Corporation's small-volume residential and commercial customers purchase their supplies from unregulated marketers. In contrast, almost all large-volume load is served by unregulated retail marketers. However, retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation, because in both jurisdictions, utility cost of service is recovered through rates and charges for gas delivery service, not gas commodity service.

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

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

Competition: The Energy Marketing Segment

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy supply. Competition in this area is well developed with regard to price and services from local, regional and national marketers.

Seasonality

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

Volumes transported and stored by Supply Corporation and volumes transported by Empire may vary materially 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.

Variations in weather conditions materially affect the volume of gas consumed by customers of the Energy Marketing segment. Volume variations have a corresponding impact on revenues within this segment.

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 I — Commitments and Contingencies.

Miscellaneous

The Company and its wholly owned or majority-owned subsidiaries had a total of 2,105 full-time employees at September 30, 2018.

The Company has agreements in place with collective bargaining units in New York and Pennsylvania. Agreements covering employees in collective bargaining units in New York are scheduled to expire in February 2021. Agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2022.

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 internet 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 internet website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

Executive Officers of the Company as of November 15, 2018(1)

Name and Age (as of November 15, 2018)	Current Company Positions and Other Material Business Experience During Past Five Years
Ronald J. Tanski (66)	Chief Executive Officer of the Company since April 2013 and President of the Company since July 2010.
John R. Pustulka (66)	Chief Operating Officer of the Company since February 2016. Mr. Pustulka previously served as President of Supply Corporation from July 2010 through January 2016.
David P. Bauer (49)	President of Supply Corporation since February 2016. Treasurer and Principal Financial Officer of the Company since July 2010. Treasurer of Seneca since April 2015; Treasurer of Distribution Corporation since April 2015; Treasurer of Midstream Company since April 2013; Treasurer of Supply Corporation since June 2007; and Treasurer of Empire since June 2007. Mr. Bauer previously served as Assistant Treasurer of Distribution Corporation from April 2004 through March 2015.
Carl M. Carlotti (63)	President of Distribution Corporation since February 2016. Mr. Carlotti previously served as Senior Vice President of Distribution Corporation from January 2008 through January 2016.
Ronald C. Kraemer (62)	President of Empire since August 2008 and Senior Vice President of Supply Corporation since June 2016. Mr. Kraemer previously served as Vice President of Supply Corporation from August 2008 through May 2016.
John P. McGinnis (58)	President of Seneca since May 2016. Mr. McGinnis previously served as Chief Operating Officer of Seneca from October 2015 through April 2016 and Senior Vice President of Seneca from March 2007 through September 2015.
Paula M. Ciprich (58)	Senior Vice President of the Company since April 2015; Secretary of the Company from July 2008 through June 2018; General Counsel of the Company since January 2005; Secretary of Distribution Corporation since July 2008.
Karen M. Camiolo (59)	Controller and Principal Accounting Officer of the Company since April 2004; Vice President of Distribution Corporation since April 2015; Controller of Midstream Company since April 2013; Controller of Empire since June 2007; and Controller of Distribution Corporation and Supply Corporation since April 2004.
Donna L. DeCarolis (59)	Vice President Business Development of the Company since October 2007.
Ann M. Wegrzyn (60)	Chief Information Officer of the Company since February 2017. Mrs. Wegrzyn previously served as Vice President of Distribution Corporation from December 2010 through January 2017.

(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

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 and other cash flow from the subsidiaries. Such operating subsidiaries may not generate sufficient net income to pay upstream dividends or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

The Company 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 maturing debt on favorable terms. 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.

In addition, the Company's short-term bank loans 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 the ability of the Company to issue commercial paper are affected by its debt credit ratings published by S&P, Moody's Investors Service, Inc. and Fitch Ratings. A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company’s subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. Additionally, $600 million of the Company’s outstanding long-term debt would be subject to an interest rate increase if certain fundamental changes occur that involve a material subsidiary and result in a downgrade of the credit ratings assigned to the notes below investment grade. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets.

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. Economic conditions in the Company’s utility service territories and energy marketing territories also impact its collections of accounts receivable. All of the Company’s segments are exposed to risks associated with the creditworthiness or performance of key suppliers and customers, many of which may be adversely affected by volatile conditions in the financial markets. These conditions could result in financial instability or other adverse effects at any of our suppliers or customers. For example, counterparties to the Company’s commodity hedging arrangements or commodity sales contracts might not be able to perform their obligations under these arrangements or contracts. Customers of the Company’s Utility and Energy Marketing segments may have particular trouble paying their bills during periods of declining economic activity or high commodity prices, potentially resulting in increased bad debt expense and reduced earnings. Similarly, if reductions were to occur in funding of the federal Low Income Home Energy Assistance Program, bad debt expense could increase and earnings could decrease. In addition, oil and gas exploration and production companies that are customers of the Company’s Pipeline and Storage segment may decide not to renew contracts for the same transportation capacity during periods of reduced production due to persistent low commodity prices. Any of these events could have a material adverse effect on the Company’s results of operations, financial condition and cash flows.

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 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.

While the Company generally refers to its Utility segment and its Pipeline and Storage segment as its "regulated segments," there are many governmental laws and regulations that have an impact on almost every aspect of the Company's businesses including, but not limited to, tax law, such as the 2017 Tax Reform Act and related regulatory action, and environmental law. Existing statutes and regulations 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. New York State, for example, under the current executive administration, appears intent on imposing unattainable regulatory standards, at least with respect to certain fossil fuel energy infrastructure projects.

Various aspects of the Company's operations are subject to regulation by, among others, the EPA, the U.S. Fish and Wildlife Service, the U.S. Forestry Service, the Bureau of Land Management, the NYDEC, the PaDEP, the Pennsylvania Department of Conservation and Natural Resources, the Division of Oil, Gas and Geothermal Resources of the California Department of Conservation, the California Department of Fish and Wildlife, and in some areas, locally adopted ordinances. Administrative proceedings or increased regulation by these or other agencies could lead to operational delays or restrictions and increased expense for one or more of the Company’s subsidiaries.

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. Compliance with new legislation could increase costs to the Company. Non-compliance with this legislation could result in civil penalties for pipeline safety violations. If as a result of these or similar new laws or regulations the Company incurs material 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, including Seneca, Distribution Corporation and NFR. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their natural 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 natural 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. The FERC also possesses significant penalty authority with respect to violations of the laws and regulations it administers. Supply Corporation, Empire and, to the extent subject to FERC jurisdiction, the Company's other subsidiaries are subject to the FERC's penalty authority. In addition, the FERC exercises jurisdiction over the construction and operation of facilities used in interstate gas transmission. Also, decisions of Canadian regulators such as the National Energy Board and the Ontario Energy Board could affect the viability

and profitability of Supply Corporation and Empire projects designed to transport gas between Canada and the United States.

In the Company's Utility segment, 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 required in a rate proceeding to reduce the rates it charges its utility customers, or to the extent Distribution Corporation is unable to obtain approval for rate increases from these regulators, particularly when necessary to cover increased costs (including costs that may be incurred in connection with governmental investigations or proceedings or mandated infrastructure inspection, maintenance or replacement programs), earnings may decrease.

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; geological formations with abnormal pressures; 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. Any of these events could cause a loss of hydrocarbons, environmental pollution, claims for personal injury, death, property damage or business interruption, or governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, the Company maintains insurance coverage against some, but not all, potential losses. In addition, many of the agreements that the Company executes with contractors provide for the division of responsibilities between the contractor and the Company, and the Company seeks to obtain an indemnification from the contractor for certain of these risks. The Company is not always able, however, to secure written agreements with its contractors that contain indemnification, and sometimes the Company is required to indemnify others.

Insurance or indemnification agreements, when obtained, may not 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.

Environmental regulation significantly affects the Company’s business.

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

In addition, the Company must obtain, maintain and comply with numerous permits, leases, approvals, consents and certificates from various governmental authorities before commencing regulated activities. In connection with such activities, the Company may need to make significant capital and operating expenditures to detect, repair and/or control air emissions, to control water discharges or to perform certain corrective actions to meet the conditions of the permits issued pursuant to applicable environmental laws and regulations. Any failure to comply with applicable environmental laws and regulations and the terms and conditions of its environmental permits and authorizations could result in the assessment of significant administrative, civil and/or criminal penalties, the imposition of investigatory or remedial obligations and corrective actions, the revocation of required permits, or the issuance of injunctions limiting or prohibiting certain of the Company's operations.

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 and regulations could require unexpected capital expenditures at the Company's facilities, temporarily shut down the Company's facilities or delay or cause the cancellation of expansion projects or oil and natural gas drilling activities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect the Company's business. Although the Company cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local laws or regulations, the Company's costs could increase if environmental laws and regulations change.

For further discussion of the risks associated with environmental regulation, refer to Item 7, MD&A under the heading "Environmental Matters" and subheading "Environmental Regulation."

Third parties may attempt to breach the Company's network security, which could disrupt the Company's operations and adversely affect its financial results.

The Company's information technology systems are subject to attempts by others to gain unauthorized access through the Internet, 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. Attempts to breach the Company's network security may result in disruption of the Company's business operations and services, delays in production, theft of sensitive and valuable data, damage to our physical systems, and reputational harm. Significant expenditures may be required to remedy breaches, including restoration of customer service and enhancement of information technology systems. The Company seeks to prevent, detect and investigate these security incidents, but in some cases the Company might be unaware of an incident or its magnitude and effects. The Company has experienced attempts to breach its network security, and although the scope of such incidents is sometimes unknown, they could prove to be material to the Company. Even though we have insurance coverage in place for cyber-related risks, if such a breach were to occur, the Company's operations, earnings and financial condition could be adversely affected to the extent not fully covered by such insurance.

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

Construction of the Pipeline and Storage segment's planned pipelines and storage facilities, as well as the expansion of existing facilities, is subject to various regulatory, environmental, political, legal, economic and other development risks, including the ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on acceptable terms, or at all. For example, the Company has in the past encountered, and may in the future encounter, delays or denials by regulatory agencies in connection with certain projects, most significantly the Northern Access 2016 project. Existing or potential third party opposition, such as opposition from landowner and environmental groups, which are beyond our control, could interfere significantly with or delay the Company's receipt of such approvals or permits, which could materially affect the anticipated construction of a project. In addition, third parties could impede the Gathering segment's acquisition, expansion or renewal of

rights-of-way or land rights on a timely basis and on acceptable terms. Any delay in project construction may prevent a planned project from going into service when anticipated, which could cause a delay in the receipt of revenues from those facilities. A significant construction delay in a material project, whatever the cause, or a final judgment denying a necessary permit, may result in asset write-offs and reduced earnings and an inability to complete projects as initially planned, or at all. These events could have a material adverse impact on anticipated operating results.

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

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

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

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

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

Operations in the Company's Exploration and Production segment are materially dependent on prices received for its oil and natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and natural gas. Oil and natural gas prices can be volatile and can be affected by: weather conditions, natural disasters, the supply and price of foreign oil and natural gas, the level of consumer product demand, national and worldwide economic conditions, economic disruptions caused by terrorist activities, acts of war or major accidents, political conditions in foreign countries, the price and availability of alternative fuels, the proximity to, and availability of, capacity on transportation facilities, regional levels of supply and demand, energy conservation measures, and government regulations, such as regulation of greenhouse gas emissions and natural gas transportation, royalties, and price controls. The Company sells the oil and 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 or the financial markets. The prices the Company receives depend upon factors beyond the Company's control, including the factors affecting price mentioned above. The Company believes that any prolonged reduction in oil and 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 revenues, cash flows and results of operations.

To the extent that the natural gas the Company produces is priced in local markets where production occurs, the price may be affected by local or regional supply and demand factors as well as other local market dynamics such as regional pipeline capacity. Currently, the prices the Company receives for its natural gas production in the local markets where production occurs are generally lower than the relevant benchmark prices, such as NYMEX, that are used for commodity trading purposes. The difference between the benchmark price and the price the Company receives is called a differential. The Company may be unable to accurately predict natural gas differentials, which may widen significantly in the future. Numerous factors may influence local commodity pricing, such as pipeline takeaway capacity and specifications, localized storage capacity, disruptions in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Insufficient pipeline or storage capacity, or a lack of demand or surplus of supply in any given operating area may cause the differential to widen in that area compared to other natural gas producing areas. Increases in the differential could lead to production curtailments or otherwise have a material adverse effect on the Company's 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 price the Company charges to transport that natural gas may decrease. Changes in price differentials can cause shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. In some cases, shippers may decide not to renew transportation contracts due to changes in price differentials. While much of the impact of lower volumes under existing contracts would be offset by the straight fixed-variable rate design utilized by Supply Corporation and Empire, 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 the Pipeline and Storage segment may decrease.

Significant changes in the price differential between futures contracts for natural 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 natural gas within the Pipeline and Storage segment's geographic area or other factors), then demand for the Company's natural gas storage services driven by that price differential could decrease. Such changes in price differential could also affect the Energy Marketing segment's ability to offset its natural gas storage costs through hedging transactions. These changes could adversely affect revenues, cash flows and results of operations.

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

In order to protect itself to some extent against unusual price volatility and to lock in fixed pricing on oil and 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 at any time cover as much as approximately 80% of the Company's expected energy production during the upcoming 12-month period. These contracts reduce exposure to subsequent price drops but can also limit the Company's ability to benefit from increases in commodity prices. In addition, the Energy Marketing segment enters into certain hedging arrangements, primarily with respect to its fixed price purchase and sales commitments and its gas stored underground.

Under applicable accounting rules currently in effect, the Company's hedging arrangements are subject to quarterly effectiveness tests. Inherent within those effectiveness tests are assumptions concerning the long-term price differential between different types of crude oil, assumptions concerning the difference between published natural gas price indexes established by pipelines into which hedged natural gas production is delivered and the reference price established in the hedging arrangements, assumptions regarding the levels of production that will be achieved and, with regard to fixed price commitments, assumptions regarding the creditworthiness of certain customers and their forecasted consumption of natural gas. Depending on market conditions for natural gas and crude oil and the levels of production actually achieved, it is possible that certain of those assumptions may change in the future, and, depending on the magnitude of any such changes, it is possible that a portion of the Company's hedges may no longer be considered highly effective. In that case, gains or losses from the ineffective derivative financial instruments would be marked-to-market on the income statement without regard to an underlying physical transaction. For example, in the Exploration and Production segment, where the Company uses short positions (i.e. positions that pay off in the event of commodity price decline) to hedge forecasted sales, gains would occur to the extent that natural gas and crude oil hedge prices exceed market prices for the Company's natural gas and crude oil production, and losses would occur to the extent that market prices for the Company's natural gas and crude oil production exceed hedge prices.

Use of energy commodity price hedges also exposes the Company to the risk of non-performance by a contract counterparty. These parties might not be able to perform their obligations under the hedge arrangements. In addition, the Company enters into certain commodity price hedges that are cleared through the NYMEX or ICE by futures commission merchants. Under NYMEX and ICE rules, the Company is required to post collateral in connection with such hedges, with such collateral being held by its futures commission merchants. The Company is exposed to the risk of loss of such collateral from occurrences such as financial failure of its futures commission merchants, or misappropriation or mishandling of clients' funds or other similar actions by its futures commission merchants. In addition, the Company is exposed to potential hedging ineffectiveness in the event of a failure by one of its futures commission merchants or contract counterparties.

It is the Company's practice that the use of commodity derivatives contracts comply with various policies in effect in respective business segments. For example, in the Exploration and Production segment, commodity derivatives contracts must be confined to the price hedging of existing and forecast production, and in the Energy Marketing segment, commodity derivatives with respect to fixed price purchase and sales commitments must be matched against commitments reasonably certain to be fulfilled. The Company maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose the Company to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of oil and 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. The act requires the CFTC, the SEC and various banking regulators to promulgate rules and regulations implementing the act. Although regulators have issued certain regulations, other rules that may be relevant to the Company have yet to be finalized.

For further discussion of the risks associated with the Dodd-Frank Act, refer to Item 7, MD&A under the heading "Market Risk Sensitive Instruments."

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

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

If conditions remain constant, then the Company is reasonably certain that its reserve estimates represent economically recoverable oil and 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 oil and 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 oil and natural gas (based on first day of the month prices and adjusted for hedging) and on costs as of the date of the estimate. 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 oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to the Company's reserve estimates in the future. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend

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upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of oil and natural gas that are ultimately recovered, the timing of the recovery of oil and natural gas reserves, the production and operating costs incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

The amount and timing of actual future oil and 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 oil and natural gas, including numerous uncertainties inherent in estimating quantities of proved oil and 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 segment depends on its ability to develop additional oil and 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, geology, and other factors. Drilling for oil and 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, 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.

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). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material. Under the Company's existing indenture covenants, an impairment could restrict the Company's ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. For the fiscal year ended September 30, 2015, the Company recognized pre-tax impairment charges on its oil and natural gas properties of $1.1 billion. For the fiscal year ended September 30, 2016, the Company recognized a pre-tax impairment charge on its oil and natural gas properties of $948.3 million.

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

Due to the burgeoning Marcellus and Utica Shale natural gas plays in the northeast United States, together with the fiscal difficulties faced by state agencies in Pennsylvania, various state legislative and regulatory initiatives

regarding the exploration and production business have been proposed or adopted. These initiatives include potential new or updated statutes and regulations governing the drilling, casing, cementing, testing, abandonment and monitoring of wells, the protection of water supplies and restrictions on water use and water rights, hydraulic fracturing operations, surface owners’ rights and damage compensation, the spacing of wells, use and disposal of potentially hazardous materials, and environmental and safety issues regarding natural gas pipelines. New permitting fees and/or severance taxes for oil and gas production are also possible. Additionally, legislative initiatives in the U.S. Congress and regulatory studies, proceedings or rule-making initiatives at federal, state or local agencies focused on the hydraulic fracturing process and related operations could result in additional permitting, compliance, reporting and disclosure requirements. For example, the EPA has adopted regulations that establish emission performance standards for hydraulic fracturing operations as well as natural gas gathering and transmission operations. Other EPA initiatives could expand water quality and hazardous waste regulation of hydraulic fracturing and related operations. In California, legislation regarding well stimulation, including hydraulic fracturing, has been adopted. The law mandates technical standards for well construction, hydraulic fracturing water management, groundwater monitoring, seismicity monitoring during hydraulic fracturing operations and public disclosure of hydraulic fracturing fluid constituents. Additionally, the California Division of Oil, Gas & Geothermal Resources (DOGGR) adopted regulations intended to bring California’s Class II Underground Injection Control (UIC) program into compliance with the federal Safe Drinking Water Act, under which some wells may require an aquifer exemption. DOGGR began reviewing all active UIC projects, regardless of whether an exemption is required. These and any other new state, federal or local legislative or regulatory measures could lead to operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risks of litigation for the Company.

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

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

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

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

Item 1B Unresolved Staff Comments

None.

Item 2 Properties

General Information on Facilities

The net investment of the Company in property, plant and equipment was $5.0 billion at September 30, 2018. The Exploration and Production segment constitutes 27.5% of this investment, and is primarily located in California and in the Appalachian region of the United States. Approximately 61.4% 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 northwestern Pennsylvania. The Gathering segment constitutes 9.9% of the Company's investment in net property, plant and equipment, and is located in northwestern Pennsylvania. The remaining net investment in property, plant and equipment consisted of the All Other category and Corporate operations (1.2%), or $0.1 billion. During the past five years, the Company has made additions to property, plant and equipment in order to expand its exploration and production operations in the Appalachian region of the United States and to expand and improve transmission facilities for transportation customers in New York and Pennsylvania. Net property, plant and equipment has decreased $175 million, or 3.4%, since September 30, 2013.

The Exploration and Production segment had a net investment in property, plant and equipment of $1.4 billion at September 30, 2018.

The Pipeline and Storage segment had a net investment of $1.6 billion in property, plant and equipment at September 30, 2018. Transmission pipeline represents 36% of this segment's total net investment and includes 2,259 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 16% of this segment's total net investment and consist of 31 storage fields operating at a combined working gas level of 77.2 Bcf, three of which are jointly owned and operated with other interstate gas pipeline companies, and 394 miles of pipeline. Net investment in storage facilities includes $81.2 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 32 compressor stations with 174,407 installed compressor horsepower that represent 26% of this segment's total net investment in property, plant and equipment.

The Gathering segment had a net investment of $0.5 billion in property, plant and equipment at September 30, 2018. Gathering lines and related compressors represent substantially all of this segment's total net investment, including 152 miles of lines utilized to move Appalachian production (including Marcellus and Utica Shales) to various transmission pipeline receipt points. The Gathering segment has 7 compressor stations with 69,340 installed compressor horsepower.

The Utility segment had a net investment in property, plant and equipment of $1.5 billion at September 30, 2018. The net investment in its gas distribution network (including 14,898 miles of distribution pipeline) and its service connections to customers represent approximately 48% and 33%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2018.

The Pipeline and Storage segments' facilities provided the capacity to meet Supply Corporation's 2018 peak day sendout for transportation service of 2,361 MMcf, which occurred on January 5, 2018. Withdrawals from storage of 628.9 MMcf provided approximately 27% of the requirements on that day.

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

Exploration and Production Activities

The Company is engaged in the exploration for and the development of natural gas and oil reserves in California and the Appalachian region of the United States. The Company has been increasing its emphasis in the Appalachian region, primarily in the Marcellus and Utica Shales. Further discussion of oil and gas producing activities is included in Item 8, Note L - Supplementary Information for Oil and Gas Producing Activities. Note L sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2018, 2017 and 2016 reserves shown in Note L are valued using an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. The reserves were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Note L discusses the qualifications of the Company's reservoir engineers, internal controls over the reserve estimation process and audit of the reserve estimates and changes in proved developed and undeveloped oil and natural gas reserves year over year.

Seneca's proved developed and undeveloped natural gas reserves increased from 1,973 Bcf at September 30, 2017 to 2,357 Bcf at September 30, 2018. This increase is attributed to extensions and discoveries of 522 Bcf and

upward revisions of previous estimates of 93 Bcf, partially offset by production of 163 Bcf and sales of minerals in place of 68 Bcf. Of the total upward gas revisions of 93 Bcf, 96 Bcf were a result of upward revisions due to performance improvements, and 2 Bcf were a result of higher gas prices, partially offset by 5 Bcf of PUD locations that were removed. The sales of minerals in place were primarily the result of Marcellus reserves that were sold in the Western Development Area as part of the joint development agreement (JDA) with IOG CRV - Marcellus, LLC (IOG)(57 Bcf), coupled with the sale of Seneca's Sespe Field area in May 2018 (11 Bcf).

Seneca's proved developed and undeveloped oil reserves decreased from 30,207 Mbbl at September 30, 2017 to 27,663 Mbbl at September 30, 2018. The decrease is attributed to production of 2,535 Mbbl, primarily occurring in the West Coast region, and sales of minerals in place of 4,787 Mbbl, partially offset by extensions and discoveries of 2,301 Mbbl and upward revisions of previous estimates of 2,477 Mbbl. The sales of minerals in place were primarily the result of the aforementioned sale of Seneca's Sespe Field area in May 2018. Upward revisions of 2,477 Mbbl were a result of both higher oil prices of 1,975 Mbbl and upward revisions associated with performance improvements of 502 Mbbl.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 2,154 Bcfe at September 30, 2017 to 2,523 Bcfe at September 30, 2018. This increase is attributed to extensions and discoveries of 536 Bcfe and upward revisions of previous estimates of 108 Bcfe, partially offset by production of 178 Bcfe and sales of minerals in place of 97 Bcfe.

Seneca's proved developed and undeveloped natural gas reserves increased from 1,675 Bcf at September 30, 2016 to 1,973 Bcf at September 30, 2017. This increase is attributed to extensions and discoveries of 386 Bcf and upward revisions of previous estimates of 91 Bcf, partially offset by production of 157 Bcf and sales of minerals in place of 22 Bcf. Of the total upward gas revisions of 91 Bcf, 125 Bcf were a result of higher gas prices for Marcellus Shale, Utica Shale and other reservoirs, and 20 Bcf were a result of upward revisions due to performance improvements and lease operating expense reductions, partially offset by 54 Bcf of PUD locations that were removed. The sales of minerals in place were the result of Marcellus and Utica reserves that were sold in the Western Development Area (primarily in Forest, Elk, McKean and Cameron counties in Pennsylvania) in September 2017.

Seneca's proved developed and undeveloped oil reserves increased from 29,009 Mbbl at September 30, 2016 to 30,207 Mbbl at September 30, 2017. The increase is attributed to extensions and discoveries of 674 Mbbl and upward revisions of previous estimates of 3,293 Mbbl, partially offset by production of 2,740 Mbbl, primarily occurring in the West Coast region, and sales of minerals in place of 29 Mbbl. Upward revisions of 3,293 Mbbl were a result of both higher oil prices of 1,623 Mbbl and upward revisions associated with performance improvements of 1,670 Mbbl. The sales of minerals in place were the result of aforementioned sales of reserves in the Western Development Area.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 1,849 Bcfe at September 30, 2016 to 2,154 Bcfe at September 30, 2017. This increase is attributed to extensions and discoveries of 391 Bcfe and upward revisions of previous estimates of 110 Bcfe, partially offset by production of 174 Bcfe and sales of minerals in place of 22 Bcfe.

At September 30, 2018, the Company's Exploration and Production segment had delivery commitments of 2,036 Bcfe (mostly natural gas as commitments for crude oil were insignificant). The Company expects to meet those commitments through proved reserves, including the future development of reserves that are currently classified as proved undeveloped 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		
	2018	2017	2016
United States			
Appalachian Region			
Average Sales Price per Mcf of Gas	$2.36 (1)	$2.52 (1)	$1.94 (1)
Average Sales Price per Barrel of Oil	$57.76	$48.27	$52.15
Average Sales Price per Mcf of Gas (after hedging)	$2.49	$2.93	$3.01
Average Sales Price per Barrel of Oil (after hedging)	$57.76	$48.27	$52.15
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$0.69 (1)	$0.71 (1)	$0.73 (1)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	440 (1)	422 (1)	385 (1)
West Coast Region			
Average Sales Price per Mcf of Gas	$4.86	$4.00	$3.25
Average Sales Price per Barrel of Oil	$66.39	$46.14	$35.26
Average Sales Price per Mcf of Gas (after hedging)	$4.86	$4.00	$3.25
Average Sales Price per Barrel of Oil (after hedging)	$58.66	$53.85	$57.97
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$2.98	$2.91	$2.47
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	48	53	56
Total Company			
Average Sales Price per Mcf of Gas	$2.40	$2.55	$1.97
Average Sales Price per Barrel of Oil	$66.38	$46.18	$35.42
Average Sales Price per Mcf of Gas (after hedging)	$2.52	$2.95	$3.02
Average Sales Price per Barrel of Oil (after hedging)	$58.66	$53.87	$57.91
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$0.91	$0.96	$0.96
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	488	475	441

(1) The Marcellus Shale fields (which exceed 15% of total reserves at September 30, 2018, 2017 and 2016) contributed 412 MMcfe, 399 MMcfe and 372 MMcfe of daily production in 2018, 2017 and 2016, respectively. The average lifting costs (per Mcfe) were $0.69 in 2018, $0.71 in 2017 and $0.72 in 2016. The Utica Shale fields (which exceed 15% of total reserves at September 30, 2018) contributed 26 MMcfe of daily production in 2018. The average lifting costs (per Mcfe) were $0.64 in 2018. The average sales price for the Marcellus and Utica Shale fields (per Mcfe) were $2.36 ($2.49 after hedging) in 2018, $2.52 ($2.93 after hedging) in 2017 and $1.94 ($3.01 after hedging) in 2016.

Productive Wells

	Appalachian Region		West Coast Region		Total Company	
At September 30, 2018	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	472	—	—	1,917	472	1,917
Productive Wells — Net	367	—	—	1,884	367	1,884

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Developed and Undeveloped Acreage

At September 30, 2018	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
— Gross	527,544	17,101	544,645
— Net	518,518	15,769	534,287
Undeveloped Acreage			
— Gross	355,110	120	355,230
— Net	341,074	30	341,104
Total Developed and Undeveloped Acreage			
— Gross	882,654	17,221	899,875
— Net	859,592 (1)	15,799	875,391

(1) Of the 859,592 Total Developed and Undeveloped Net Acreage in the Appalachian region as of September 30, 2018, there are a total of 800,683 net acres in Pennsylvania. Of the 800,683 total net acres in Pennsylvania, shale development in the Marcellus, Utica or Geneseo shales has occurred on approximately 57,846 net acres, or 7.2% of Seneca's total net acres in Pennsylvania. The high amount of developed acreage in the table largely reflects development in the Upper Devonian geological formation and masks the potential for development beneath this formation, which includes the Marcellus, Utica and Geneseo shales.

As of September 30, 2018, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 3,704 acres in 2019 (3,704 net acres), 446 acres in 2020 (356 net acres), 2 acres in 2021 (2 net acres) and 37,830 acres thereafter (36,735 net acres). The remaining 313,248 gross acres (300,307 net acres) represent non-expiring oil and gas rights owned by the Company. Of the acreage that is currently scheduled to expire in 2019, 2020 and 2021, Seneca has no 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

	Productive			Dry		
For the Year Ended September 30	2018	2017	2016	2018	2017	2016
United States						
Appalachian Region						
Net Wells Completed						
— Exploratory	4.00	9.00	1.00	—	—	—
— Development	41.40	25.40	31.80	9.00	3.00	1.00
West Coast Region						
Net Wells Completed						
— Exploratory	—	—	—	—	—	—
— Development	15.00	14.00	25.00	—	—	—
Total Company						
Net Wells Completed						
— Exploratory	4.00	9.00	1.00	—	—	—
— Development	56.40	39.40	56.80	9.00	3.00	1.00

Present Activities

At September 30, 2018	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
— Gross	63.00	—	63.00
— Net	48.50	—	48.50

(1) Includes wells awaiting completion.

Item 3 Legal Proceedings

On September 13, 2017, the PaDEP sent a draft Consent Assessment of Civil Penalty (CACP) to Seneca, in relation to an alleged violation of the Pennsylvania Oil and Gas Act, as well as PaDEP rules and regulations regarding gas migration relating to Seneca's drilling activities. The amount of the penalty sought by the PaDEP is not material to the Company. The draft CACP alleges a violation identified by the PaDEP in 2011. Seneca disputes the alleged violation and will vigorously defend its position in negotiations with the PaDEP.

For a discussion of various environmental and other matters, refer to Part II, Item 7, MD&A and Item 8 at Note I — 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 and Regulatory 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, 2018, there were 10,751 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 E — Capitalization and Short-Term Borrowings.

On July 2, 2018, the Company issued a total of 6,616 unregistered shares of Company common stock to the eight non-employee directors of the Company then serving on the Board of Directors of the Company, 827 shares to each such director. On July 16, 2018, the Company issued 707 unregistered shares of Company stock to Steven C. Finch, who joined the Board on July 12, 2018 as a non-employee 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, 2018. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs(b)
July 1-31, 2018	9,542	$ 54.66	—	6,971,019
Aug. 1-31, 2018	10,972	$ 55.51	—	6,971,019
Sept. 1-30, 2018	10,311	$ 56.63	—	6,971,019
Total	30,825	$ 55.62	—	6,971,019

(a) Represents (i) shares of common stock of the Company purchased on the open market with Company “matching contributions” for the accounts of participants in the Company’s 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock-based compensation awards for the payment of applicable withholding taxes. During the quarter ended September 30, 2018, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 30,825 shares purchased other than through a publicly announced share repurchase program, 28,089 were purchased for the Company’s 401(k) plans and 2,736 were purchased as a result of shares tendered to the Company by holders of stock-based compensation awards.

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

Performance Graph

The following graph compares the Company’s common stock performance with the performance of the S&P 500 Index, the PHLX Utility Sector Index and the S&P 500 Oil & Gas Exploration & Production SUB Industry Index GICS Level 4 for the period September 30, 2013 through September 30, 2018. The graph assumes that the value of the investment in the Company’s common stock and in each index was $100 on September 30, 2013 and that all dividends were reinvested.

	2013	2014	2015	2016	2017	2018
National Fuel	$100	$104	$76	$85	$92	$94
S&P 500 Index	$100	$120	$119	$137	$163	$192
PHLX Utility Sector Index (UTY)	$100	$116	$122	$144	$162	$167
S&P 500 Oil & Gas Exp & Prod SUB Industry Index GICS Level 4 (S5OILP)	$100	$108	$63	$76	$68	$85

Source: Bloomberg

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

Item 6 Selected Financial Data

	Year Ended September 30				
	2018	2017	2016	2015	2014
	(Thousands, except per share amounts and number of registered shareholders)				
Summary of Operations					
Operating Revenues:					
Utility and Energy Marketing Revenues	$ 812,474	$ 755,485	$ 624,602	$ 860,618	$ 1,103,149
Exploration and Production and Other Revenues	569,808	617,666	611,766	696,709	808,595
Pipeline and Storage and Gathering Revenues	210,386	206,730	216,048	203,586	201,337
	1,592,668	1,579,881	1,452,416	1,760,913	2,113,081
Operating Expenses:					
Purchased Gas	337,822	275,254	147,982	349,984	605,838
Operation and Maintenance:					
Utility and Energy Marketing	200,780	199,293	192,512	203,249	196,534
Exploration and Production and Other	141,381	145,099	160,201	184,024	188,622
Pipeline and Storage and Gathering	100,245	98,200	88,801	82,730	77,922
Property, Franchise and Other Taxes	84,393	84,995	81,714	89,564	90,711
Depreciation, Depletion and Amortization	240,961	224,195	249,417	336,158	383,781
Impairment of Oil and Gas Producing Properties	—	—	948,307	1,126,257	—
	1,105,582	1,027,036	1,868,934	2,371,966	1,543,408
Operating Income (Loss)	487,086	552,845	(416,518)	(611,053)	569,673
Other Income (Expense):					
Other Income	4,697	7,043	9,820	8,039	9,461
Interest Income	6,766	4,113	4,235	3,922	4,170
Interest Expense on Long-Term Debt	(110,946)	(116,471)	(117,347)	(95,916)	(90,194)
Other Interest Expense	(3,576)	(3,366)	(3,697)	(3,555)	(4,083)
Income (Loss) Before Income Taxes	384,027	444,164	(523,507)	(698,563)	489,027
Income Tax Expense (Benefit)	(7,494)	160,682	(232,549)	(319,136)	189,614
Net Income (Loss) Available for Common Stock	$ 391,521	$ 283,482	$ (290,958)	$ (379,427)	$ 299,413
Per Common Share Data					
Basic Earnings (Loss) per Common Share	$ 4.56	$ 3.32	$ (3.43)	$ (4.50)	$ 3.57
Diluted Earnings (Loss) per Common Share	$ 4.53	$ 3.30	$ (3.43)	$ (4.50)	$ 3.52
Dividends Declared	$ 1.68	$ 1.64	$ 1.60	$ 1.56	$ 1.52
Dividends Paid	$ 1.67	$ 1.63	$ 1.59	$ 1.55	$ 1.51
Dividend Rate at Year-End	$ 1.70	$ 1.66	$ 1.62	$ 1.58	$ 1.54
At September 30:					
Number of Registered Shareholders	10,751	11,211	11,751	12,147	12,654

	Year Ended September 30				
	2018	2017	2016	2015	2014
	(Thousands, except per share amounts and number of registered shareholders)				
Net Property, Plant and Equipment					
Exploration and Production	$ 1,370,340	$ 1,196,521	$ 1,083,804	$ 2,126,265	$ 2,897,744
Pipeline and Storage	1,583,699	1,524,197	1,463,541	1,387,516	1,187,924
Gathering	493,694	455,701	439,660	400,409	292,793
Utility	1,469,645	1,435,414	1,403,286	1,351,504	1,297,179
Energy Marketing	1,267	1,503	1,745	1,989	2,070
All Other	56,295	57,960	59,054	60,404	61,236
Corporate	2,203	2,778	3,392	3,808	4,145
Total Net Plant	$ 4,977,143	$ 4,674,074	$ 4,454,482	$ 5,331,895	$ 5,743,091
Total Assets	$ 6,036,486	$ 6,103,320	$ 5,636,387	$ 6,564,939	$ 6,687,717
Capitalization					
Comprehensive Shareholders’ Equity	$ 1,937,330	$ 1,703,735	$ 1,527,004	$ 2,025,440	$ 2,410,683
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,131,365	2,083,681	2,086,252	2,084,009	1,637,443
Total Capitalization	$ 4,068,695	$ 3,787,416	$ 3,613,256	$ 4,109,449	$ 4,048,126

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, distribution and marketing of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current development activities are focused primarily in the Marcellus and Utica Shale. The common geographic footprint of the Company’s subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian basin to markets in Canada and the eastern United States. The Company's efforts in this regard are not limited to affiliated projects. The Company has also been designing and building pipeline projects for the transportation of natural gas for non-affiliated natural gas producers in the Appalachian basin. The Company also develops and produces oil reserves, primarily in California. The Company reports financial results for five business segments. Refer to Item 1, Business, for a more detailed description of each of the segments.

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. In addition, the Company strives to comply with all applicable legal and regulatory requirements and to adhere to high standards of ethics and integrity. The Board retains oversight of safety, environmental, social, cybersecurity and corporate governance risks, among other areas central to corporate responsibility. An important aspect of that oversight is the Enterprise Risk Management process. Management reports quarterly to the Board on significant risk categories. In addition, Management provides a detailed presentation on a topic related to one or more risk categories at each Board meeting.

The Board directs management to integrate corporate responsibility concerns into decision-making throughout the organization. The Company takes very seriously its role as a corporate citizen and remains committed to the welfare of the areas in which it operates, as it has for over 100 years. Toward that end, the Company has affirmed six “Guiding Principles” (Safety, Environmental Stewardship, Community, Innovation, Satisfaction and Transparency). These principles reflect and promote a culture that is committed to the tenets of corporate responsibility.

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

The U.S. Energy Information Administration (EIA) provides relevant data and projections in this regard. The EIA’s 2017 International Energy Outlook projects that worldwide natural gas consumption will increase 43% from 2015 through 2040. Natural gas is a versatile fuel and this increase is projected to transcend all sectors, with the largest increases seen in the industrial and electric generation sectors. The EIA’s 2018 Annual Energy Outlook further projects that, through 2050, U.S. natural gas consumption will increase more than any other fuel source and will account for the largest share of total energy production. The EIA anticipates that shale gas and tight oil production could potentially account for 75% of U.S. natural gas production by 2050 as companies leverage technological advances in horizontal drilling and hydraulic fracturing to develop previously uneconomic or unreachable reserves. The EIA anticipates that “continued development of the Marcellus and Utica plays in the East is the main driver of growth in total U.S. shale gas production[.]” Management reviews these, and other, projections with the Board which considers such projections in setting and reviewing the Company’s capital budget.

The Company believes that its conservative approach to capital investments combined with its history, experience, assets, and fully-integrated approach put it in a position for success in the current and evolving regulatory landscape. As recognized by the EIA, natural gas is a clean fossil fuel when compared to other fossil fuels such as oil or coal with respect to greenhouse gas emissions. In its 2018 New York State Greenhouse Gas Inventory Report, the New York State Energy Research and Development Authority noted that from 1990 to 2015, “emissions from electricity generated in-State dropped 54 percent during this . . . period, acting as a major driver of New York State’s decreasing GHG emissions. This drop is due in part to the significant decrease in the burning of coal and petroleum products in the electricity generation sector. Emissions from residential, commercial, and industrial buildings also decreased, showing a reduction of approximately 16 percent from 1990 to 2015. This reduction in emissions was driven by a decrease in the use of coal and petroleum, paired with an increase in the use of natural gas.” The Company believes that ongoing development of natural gas will help drive a continued reduction in overall greenhouse gas emissions.

The Company recognizes that there exists an evolving landscape of international accords and federal, state and local laws and regulations regarding greenhouse gas emissions or climate change initiatives. 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. The Company adjusts its approach to capital investment in response to regulatory change. For instance, given what appears to be the imposition of unattainable regulatory standards by the current executive administration of one of the states in which the Company does business, the Company is shifting its investment focus away from that state with respect to new pipeline expansion projects.

While natural gas has lower greenhouse gas emissions than other fossil fuels, the natural gas value chain does result in greenhouse gas emissions. The Company recognizes the important role of ongoing system modernization and efficiency in reducing greenhouse gas emissions. In its Utility, the Company directs capital spending to replacement and to other investments (such as the purchase of vehicles and equipment necessary for that activity) that support its statutory obligation to provide safe and reliable service. In its Pipeline and Storage businesses, a significant portion of the capital budget is spent on modernization, including leveraging expansion projects to also upgrade existing infrastructure. In its Exploration and Production segment, the Company has implemented initiatives throughout the drilling process that are aimed at minimizing greenhouse gas emissions and improving air quality, including green completion techniques and deploying leak detection technologies. Likewise, the Exploration and Production segment recognizes the importance of efficient and innovative water

sourcing, handling and recycling. To assist in water management, the Company established a water logistics company, Highland Field Services, to improve its water resourcing and recycling capabilities.

The Company’s replacement of older natural gas infrastructure leads to fewer leaks and directly results in lower greenhouse gas emissions. For instance, as a result of system modernization, the Utility segment, from 2012 to 2017, has seen a 17.4% reduction in greenhouse gas emissions, primarily methane, reported to the EPA under Subpart W of 40 CFR Part 98.

The Company also works with various regulatory commissions to develop ratemaking initiatives to increase end use efficiency while reducing downside risk from demand fluctuation. In addition, in 2018 subsidiaries of the Company’s Utility, Pipeline and Storage, Midstream and Exploration and Production segments all joined the EPA's Natural Gas STAR Methane Challenge Program and made commitments to adopt practices aimed at reducing methane emissions.

Fiscal 2018 Highlights

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

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, “Results of Operations;”
3. Operating, investing and financing cash flows under the heading “Capital Resources and Liquidity;”
4. Off-Balance Sheet Arrangements;
5. Contractual Obligations; and
6. Other Matters, including: (a) 2018 and projected 2019 funding for the Company’s pension and other post-retirement benefits; (b) disclosures and tables concerning market risk sensitive instruments; (c) rate and regulatory matters in the Company’s New York, Pennsylvania and FERC-regulated jurisdictions; (d) environmental matters; and (e) new authoritative accounting and financial reporting guidance.

The information in MD&A should be read in conjunction with the Company’s financial statements in Item 8 of this report.

For the year ended September 30, 2018 compared to the year ended September 30, 2017, the Company experienced an increase in earnings of $108.0 million. As a result of the 2017 Tax Reform Act, the effective tax rate for the year ended September 30, 2018 of negative 2.0% reflects a lower statutory rate of 24.5% as well as the impact of a remeasurement of the Company's accumulated deferred income tax liability based upon the new tax rates, recorded as a $103.5 million reduction to income tax expense. The Company's non-regulated operations are benefiting from the 2017 Tax Reform Act. With regard to the Company's regulated operations, Distribution Corporation's New York and Pennsylvania jurisdictions have received orders requiring rate reductions associated with the 2017 Tax Reform Act. In the Pipeline and Storage segment, Supply Corporation will be making a filing with FERC by December 6, 2018 to address the impact of tax reform. For Empire, the impact of tax reform is being addressed in its current section 4 rate case. For further discussion of the impact of the 2017 Tax Reform Act to the Company, refer to Rate and Regulatory Matters below and to Item 8 at Note D — Income Taxes. For further discussion of the Company’s earnings, refer to the Results of Operations section below.

On February 3, 2017, the Company, in its Pipeline and Storage segment, received FERC approval of a project to move significant prospective Marcellus production from Seneca’s Western Development Area at Clermont to an Empire interconnection with TransCanada Pipeline at Chippawa and an interconnection with Tennessee Gas Pipeline’s 200 Line in East Aurora, New York (“Northern Access project”). On April 7, 2017, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received on January 27, 2017). On April 21, 2017, the Company appealed the NYDEC's decision with regard to the Water Quality Certification to the United States Court of Appeals for the Second Circuit, and on May 11, 2017, the Company commenced legal action in New York State Supreme Court challenging the NYDEC's actions with regard to various state permits. On August 6, 2018, the FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. Rehearing requests have been filed at FERC. The Company remains committed to the project. In light of these pending legal actions and the need to complete necessary project development activities in advance of construction, the target in-service date for the project is expected to be no earlier than the first half of fiscal 2022. Approximately $76.2 million in costs have been incurred on this project through September 30, 2018, with the costs residing either in Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet, or Deferred Charges. For further discussion of the Northern Access project, refer to Item 8 at Note I — Commitments and Contingencies.

While legal proceedings continue on the Northern Access project, the Company continues to pursue development projects to expand its Pipeline and Storage segment. One project on Empire’s system, referred to as the Empire North Project, would allow for the transportation of 205,000 Dth per day of additional shale supplies from interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline, and the TGP 200 Line. The Empire North Project has a projected in-service date in the second half of fiscal 2020 and an estimated cost of approximately $145 million. Another project on Supply Corporation’s system, referred to as the FM 100 Project, is currently in the pre-filing process at FERC and will upgrade 1950’s era pipeline in northwestern Pennsylvania and create approximately 330,000 Dth per day of additional capacity on Supply Corporation’s system in Pennsylvania from a receipt point with NFG Midstream Clermont, LLC in McKean County, Pennsylvania to the Transcontinental Gas Pipe Line Company, LLC system at Leidy, Pennsylvania. The FM 100 Project has a target in-service date in late calendar 2021 and a preliminary cost estimate of approximately $280 million. These and other projects are discussed in more detail in the Capital Resources and Liquidity section that follows.

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

From a financing perspective, in August 2018, the Company issued $300.0 million of 4.75% notes due in September 2028. The proceeds of the debt issuance were used for general corporate purposes, including the September 2018 redemption of $250.0 million of the Company's 8.75% notes that were scheduled to mature in May 2019. The Company expects to use cash on hand and cash from operations to meet its capital expenditure needs for fiscal 2019 and may issue short-term and/or long-term debt during fiscal 2019 as needed.

CRITICAL ACCOUNTING ESTIMATES

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

Oil and Gas Exploration and Development Costs. In the Company’s Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this accounting methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities. The Company does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

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

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions to or subtractions from proved reserves and significant fluctuations in oil and gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment charge must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. At September 30, 2018, the ceiling exceeded the book value of the oil and gas properties by approximately \$569.1 million. The 12-month average of the first day of the month price for crude oil for each month during 2018, based on posted Midway Sunset prices, was \$64.09 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2018, based on the quoted Henry Hub spot price for natural gas, was \$2.91 per MMBtu. (Note — because actual pricing of the Company’s various producing properties varies depending on their location and hedging, the prices used to calculate the ceiling may differ from the Midway Sunset and Henry Hub prices, which are only indicative of the 12-month average prices for 2018. Pricing differences would include adjustments for regional market differentials, transportation fees and contractual arrangements.) The following table illustrates the sensitivity of the ceiling test calculation to commodity price changes, specifically showing the amounts the ceiling would have exceeded the book value of the Company's oil and gas properties at September 30, 2018 (which would not have resulted in an impairment charge) if natural gas prices were \$0.25 per MMBtu lower than the average prices used at September 30, 2018, if crude oil prices were \$5 per Bbl lower than the average prices used at September 30, 2018, and if both natural gas prices and crude oil prices were \$0.25 per MMBtu and \$5 per Bbl lower than the average prices used at September 30, 2018 (all amounts are presented after-tax). These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation, including, among others, changes in reserve quantities and future cost estimates.

Ceiling Testing Sensitivity to Commodity Price Changes

(Millions)	$0.25/MMBtu Decrease in Natural Gas Prices	$5.00/Bbl Decrease in Crude Oil Prices	$0.25/MMBtu Decrease in Natural Gas Prices and $5.00/Bbl Decrease in Crude Oil Prices
Excess of Ceiling over Book Value under Sensitivity Analysis	$ 391.1	$ 536.1	$ 358.1

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 oil and gas prices have an impact on the amount of the ceiling at any point in time.

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

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

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

Accounting for Derivative 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 crude oil in its Exploration and Production and Energy Marketing segments. These instruments are categorized as price swap agreements and futures contracts. In accordance with the authoritative guidance for derivative instruments and hedging activities, the Company primarily accounts for these instruments as effective cash flow hedges or fair value hedges. 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. Gains or losses associated with the derivative financial instruments that are accounted for as cash flow or fair value hedges are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that such derivative financial instruments would ever be deemed to be ineffective based on effectiveness testing, mark-to-

market gains or losses from such derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction. Refer to the “Market Risk Sensitive Instruments” section below for further discussion of the Company’s derivative financial instruments and refer to Item 8 at Note F— Fair Value Measurements for discussion of the determination of fair value for derivative financial instruments.

Pension and Other Post-Retirement Benefits. The amounts reported in the Company’s financial statements related to its pension and other post-retirement benefits are determined on an actuarial basis, which uses many assumptions in the calculation of such amounts. These assumptions include the discount rate, the expected return on plan assets, the rate of compensation increase and, for other post-retirement benefits, the expected annual rate of increase in per capita cost of covered medical and prescription benefits. The Company determines the service and interest cost components of net periodic benefit cost using the spot rate approach. Under this approach, the Company uses individual spot rates along the yield curve that correspond to the timing of each benefit payment in order to determine the discount rate. The individual spot rates along the yield curve are determined by an above mean methodology in that the coupon interest rates that are in the lower 50th percentile are excluded based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities. The expected return on plan assets assumption used by the Company reflects the anticipated long-term rate of return on the plan’s current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan’s target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets. Changes in actuarial assumptions and actuarial experience, including deviations between actual versus expected return on plan assets, could have a material impact on the amount of pension and post-retirement benefit costs and funding requirements experienced by the Company. However, the Company expects to recover a substantial portion of its net periodic pension and other post-retirement benefit costs attributable to employees in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorization, subject to applicable accounting requirements for rate-regulated activities, as discussed above under “Regulation.”

Changes in actuarial assumptions and actuarial experience could also have an impact on the benefit obligation and the funded status related to the Company’s pension and other post-retirement benefits and could impact the Company’s equity. For example, the discount rate used to determine benefit obligations of the Company's other post-retirement benefits changed from 3.81% in 2017 to 4.31% in 2018. The change in the discount rate from 2017 to 2018 decreased the accumulated post-retirement benefit obligation by $25.8 million. The discount rate used to determine benefit obligations of the Retirement Plan changed from 3.77% in 2017 to 4.30% in 2018. The change in the discount rate from 2017 to 2018 decreased the Retirement Plan projected benefit obligation by $58.1 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligation and the accumulated post-retirement benefit obligation. For 2018, the actual return on plan assets was lower than the expected return, which resulted in a decrease to the funded status of the Retirement Plan ($19.1 million) as well as a decrease to the funded status of the VEBA trusts and 401(h) accounts ($10.8 million). The actual versus expected benefit payments for 2018 caused a decrease of $2.1 million to the accumulated post-retirement benefit obligation. In addition, changes in per-capita claim costs, premiums, retiree contributions and retiree drug subsidy assumptions in order to better reflect anticipated experience based on actual experience resulted in an increase to the accumulated post-retirement benefit obligation of $3.8 million. In calculating the projected benefit obligation for the Retirement Plan and the accumulated post-retirement obligation, the actuary takes into account the average remaining service life of active participants. The average remaining service life of active participants is 7 years for the Retirement Plan and 5 years for those eligible for other post-retirement benefits. For further discussion of the Company’s pension and other post-retirement benefits, refer to Other Matters in this Item 7, which includes a discussion of funding for the current year, and to Item 8 at Note H — Retirement Plan and Other Post Retirement Benefits.

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

The Company has determined a reasonable estimate under Staff Accounting Bulletin (SAB) 118 for the measurement of the changes in deferred income taxes in the September 30, 2018 financial statements. The final determination of the impact of the income tax effects of these items will require further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Treasury regulations, state income tax guidance, federal and state regulatory guidance, and possible technical corrections, which, if issued, the Company expects to finalize within SAB 118's measurement period (quarter ended December 31, 2018). Any subsequent guidance will be accounted for in the period issued. For further discussion of the impact of the 2017 Tax Reform Act to the Company, refer to Item 8 at Note D — Income Taxes.

RESULTS OF OPERATIONS

EARNINGS

2018 Compared with 2017

The Company's earnings were $391.5 million in 2018 compared with earnings of $283.5 million in 2017. The increase in earnings of $108.0 million was primarily a result of higher earnings in the Exploration and Production segment, Gathering segment, Pipeline and Storage segment and Utility segment, as well as a lower loss in the All Other category. Lower earnings in the Energy Marketing segment, as well as a loss in the Corporate category, partially offset these increases. 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 event in 2018:

2018 Event

- A $103.5 million remeasurement of accumulated deferred income taxes and a lower statutory rate of 24.5% as a result of the 2017 Tax Reform Act.

2017 Compared with 2016

The Company's earnings were $283.5 million in 2017 compared to a loss of $291.0 million in 2016. The increase in earnings of $574.5 million was primarily a result of higher earnings in the Exploration and Production segment and Gathering segment. Lower earnings in the Pipeline and Storage segment, Utility segment and Energy Marketing segment, as well as losses in the Corporate and All Other categories, partially offset these increases. Earnings were impacted by the following events in 2016:

2016 Events

- Non-cash impairment charges of $948.3 million ($550.0 million after tax) recorded during 2016 for the Exploration and Production segment’s oil and gas producing properties.
- Joint development agreement professional fees of $4.6 million recorded in the Exploration and Production segment. The joint development agreement professional fees incurred were related to professional services associated with the Marcellus Shale drilling joint development agreement with IOG executed on December 1, 2015 and subsequently extended on June 13, 2016.

Earnings (Loss) by Segment

	Year Ended September 30		
	2018	2017	2016
	(Thousands)		
Exploration and Production	$180,632	$129,326	$(452,842)
Pipeline and Storage	97,246	68,446	76,610
Gathering	83,519	40,377	30,499
Utility	51,217	46,935	50,960
Energy Marketing	373	1,509	4,348
Total Reported Segments	412,987	286,593	(290,425)
All Other	(112)	(342)	778
Corporate	(21,354)	(2,769)	(1,311)
Total Consolidated	$391,521	$283,482	$(290,958)

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2018	2017	2016
	(Thousands)		
Gas (after Hedging)	$410,716	$462,976	$433,357
Oil (after Hedging)	148,693	147,599	169,263
Gas Processing Plant	4,036	3,181	2,411
Other	1,102	843	2,082
Operating Revenues	$564,547	$614,599	$607,113

Production

	Year Ended September 30		
	2018	2017	2016
Gas Production (MMcf)			
Appalachia	160,499	154,093	140,457
West Coast	2,407	2,995	3,090
Total Production	162,906	157,088	143,547
Oil Production (Mbbl)			
Appalachia	4	4	28
West Coast	2,531	2,736	2,895
Total Production	2,535	2,740	2,923

Average Prices

	Year Ended September 30		
	2018	2017	2016
Average Gas Price/Mcf			
Appalachia	$2.36	$2.52	$1.94
West Coast	$4.86	$4.00	$3.25
Weighted Average	$2.40	$2.55	$1.97
Weighted Average After Hedging(1)	$2.52	$2.95	$3.02
Average Oil Price/Barrel (Bbl)			
Appalachia	$57.76	$48.27	$52.15
West Coast	$66.39	$46.14	$35.26
Weighted Average	$66.38	$46.18	$35.42
Weighted Average After Hedging(1)	$58.66	$53.87	$57.91

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

2018 Compared with 2017

Operating revenues for the Exploration and Production segment decreased $50.1 million in 2018 as compared with 2017. Gas production revenue after hedging decreased $52.3 million primarily due to a $0.43 per Mcf decrease in the weighted average price of gas after hedging partially offset by a 5.8 Bcf increase in gas production. The increase in production was primarily due to new Marcellus and Utica wells completed and connected to sales in the Western and Eastern Development Areas during the year coupled with a decrease in price-related curtailments during fiscal 2018 compared to fiscal 2017. These decreases to operating revenues were slightly offset by an increase in oil production revenue after hedging of $1.1 million. The increase in oil production revenue after hedging was due to a $4.79 per Bbl increase in the weighted average price of oil after hedging, partially offset by a 205 Mbbl decrease in crude oil production. The decrease in crude oil production was largely due to lower production in the West Coast region as a result of the sale of Seneca's Sespe properties in May 2018. In addition, gas processing plant revenue increased $0.9 million and other revenue increased $0.3 million.

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

2017 Compared with 2016

Operating revenues for the Exploration and Production segment increased $7.5 million in 2017 as compared with 2016. Gas production revenue after hedging increased $29.6 million primarily due to a 13.5 Bcf increase in gas production partially offset by a $0.07 per Mcf decrease in the weighted average price of gas after hedging. The increase in production was primarily due to a significant decrease in price-related curtailments during fiscal 2017 compared to fiscal 2016. This was partially offset by the impact of a joint development agreement with IOG CRV - Marcellus, LLC (IOG) (lower net revenue interest in producing wells), production declines on wells in the Eastern Development Area (Tioga and Lycoming counties in Pennsylvania) and the expected impact of changing from a 3-drilling rig program to a 1-drilling rig program. For further discussion of the joint development agreement with IOG, refer to Item 8 at Note A — Summary of Significant Accounting Policies under the heading "Property, Plant and Equipment." In addition, gas processing plant revenue increased $0.8 million due to an increase in price and volumes. These increases to operating revenues were partially offset by a decrease in oil production revenue after hedging of $21.7 million due to a 183 Mbbl decrease in crude oil production coupled with a $4.04 per Bbl decrease in the weighted average price of oil after hedging. The decrease in crude oil production was largely due to the current year impact of decreased steam operations and well workover activity at its North Midway Sunset field in prior years (due to lower crude oil prices). In addition, other revenue decreased $1.2 million largely due to the impact of mark-to-market adjustments related to hedging ineffectiveness.

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Earnings

2018 Compared with 2017

The Exploration and Production segment's earnings for 2018 were $180.6 million, compared with earnings of $129.3 million for 2017, an increase of $51.3 million. The increase in earnings was primarily attributable to lower income tax expense driven largely by the impact of the 2017 Tax Reform Act, which resulted in a remeasurement of accumulated deferred taxes ($73.7 million) and reduced the Company's federal tax rate resulting in lower income tax expense on current year earnings ($20.1 million). Offsetting these positive impacts on income tax expense were the combined impact of deferred state income tax adjustments recorded in the current and prior year which lowered earnings year over year ($8.1 million).

In addition to the net positive impact on earnings from lower income tax expense, fiscal 2018 earnings benefited from higher crude oil prices after hedging ($7.9 million), higher natural gas production ($11.1 million), lower production expenses ($2.1 million), lower other operating expenses ($0.3 million), lower other taxes ($0.7 million), and lower interest expense ($0.2 million). The decrease in production expense was largely due to the aforementioned sale of Seneca's Sespe properties in May 2018, coupled with the sales of unconventional wells to Pin Oak in September 2017 and sales of compressors to Midstream Company in March 2018. These decreases in production expense were partially offset by increased gathering and transportation costs in the Appalachian region.

These factors, which contributed to increased earnings during fiscal 2018 compared to fiscal 2017, were partially offset by lower natural gas prices after hedging ($45.1 million), lower crude oil production ($7.2 million), higher depletion expense ($7.6 million), and a loss recognized on reacquired debt ($0.6 million). The increase in depletion expense, which is computed using the units of production method, was primarily due to the increase in production coupled with a $0.05 per Mcfe increase in the depletion rate. During the fourth quarter of fiscal 2018, the Exploration and Production segment recognized a loss on the redemption of long-term debt for its share of the premium paid by the Company to redeem $250 million of the Company's 8.75% notes that were scheduled to mature in May 2019.

2017 Compared with 2016

The Exploration and Production segment's earnings for 2017 were $129.3 million, an increase of $582.1 million when compared with a loss of $452.8 million for 2016. The increase in earnings primarily reflected the non-recurrence of impairment charges for oil and gas producing properties ($550.0 million). It also reflected higher natural gas production ($26.6 million), lower depletion expense ($17.8 million), lower other operating expenses ($2.2 million), lower interest expense ($1.1 million), the non-recurrence of joint development agreement professional fees ($4.6 million) and lower income tax expense ($10.6 million). The decrease in depletion expense was primarily due to a lower level of capitalized costs as a result of the impairment charges recognized in fiscal 2015 and fiscal 2016. The decrease in other operating expenses was primarily due to a decrease in personnel costs coupled with a decrease in plugging and abandonment expense (as a result of the sale of Upper Devonian wells in Pennsylvania in June 2016), which was partially offset by a contract suspension payment to TransCanada related to transportation services for the Northern Access project. The decrease in interest expense was largely due to a decrease in the Exploration and Production segment's intercompany short-term borrowings. The decrease in income tax expense was largely due to an increase in anticipated firm transportation of natural gas to delivery points outside of Pennsylvania as a result of forecasted deliveries to the Atlantic Sunrise Pipeline. This had the effect of decreasing the effective tax rate used in the calculation of deferred tax expense. Income tax expense also decreased due to an enhanced oil recovery tax credit related to Seneca's California properties, which was applicable in fiscal 2017 as a result of relatively low domestic crude oil prices. The joint development agreement professional fees incurred were related to professional services associated with the Marcellus Shale drilling joint development agreement with IOG executed in December 2015 and extended in June 2016. These fees did not recur during fiscal 2017.

These factors, which contributed to increased earnings during fiscal 2017 compared to fiscal 2016, were partially offset by lower crude oil prices after hedging ($7.2 million), lower natural gas prices after hedging ($7.3 million), lower crude oil production ($6.9 million), higher production costs ($7.9 million) and higher other taxes ($1.1 million). The increase in production costs was largely due to an increase in transportation costs associated with higher gas production volume (mostly transported by Midstream Company) coupled with increased well repairs, equipment rentals, contract labor and steam fuel costs in the West Coast region, which will support

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production in future years. These were partially offset by lower repair and maintenance costs associated with operating wells in Appalachia (impacted by the sale of Upper Devonian related wells in June 2016). The increase in other taxes was largely due to higher impact fees related to Appalachian production in fiscal 2017 compared to fiscal 2016. Impact fees were significantly lower in fiscal 2016 as a result of IOG's reimbursement of such costs for years prior to fiscal 2016. The increase in other taxes also reflected an increase in Appalachian franchise taxes, partially offset by a decrease in Kern, Ventura and Coalinga County taxes in the West Coast region due to lower crude oil prices.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2018	2017	2016
	(Thousands)		
Firm Transportation	$222,908	$221,609	$229,895
Interruptible Transportation	1,422	1,690	3,995
	224,330	223,299	233,890
Firm Storage Service	74,486	69,963	70,351
Interruptible Storage Service	23	19	143
	74,509	69,982	70,494
Other	1,487	1,144	2,045
	$300,326	$294,425	$306,429

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2018	2017	2016
Firm Transportation	764,320	779,382	740,875
Interruptible Transportation	3,546	5,805	23,548
	767,866	785,187	764,423

2018 Compared with 2017

Operating revenues for the Pipeline and Storage segment increased $5.9 million in 2018 as compared with 2017. The increase in operating revenues was primarily due to demand charges for transportation service from Supply Corporation's Line D Expansion, which was placed in service on November 1, 2017, an increase in reservation charges for storage service from new storage contracts as a result of Supply Corporation's acquisition of the remaining interest in a jointly owned storage field and an increase in both transportation and storage revenues due to Supply Corporation's greenhouse gas and pipeline safety surcharge effective November 1, 2017. Partially offsetting these increases was a decline in transportation revenues due partially to an additional 2% reduction in Supply Corporation's rates effective November 1, 2016, which was required by the rate case settlement approved by FERC on November 13, 2015, and a decline in demand charges for transportation services as a result of contract terminations.

Transportation volume decreased by 17.3 Bcf in 2018 as compared with 2017. The decrease in transportation volume primarily reflects a reduction in capacity utilization by certain contract shippers combined with contract terminations. Volume fluctuations, other than those caused by the addition or termination of contracts, generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

2017 Compared with 2016

Operating revenues for the Pipeline and Storage segment decreased $12.0 million in 2017 as compared with 2016. The decrease was primarily due to a decrease in transportation revenues of $10.6 million. The decline in transportation revenues was due partially to a 2% reduction in Supply Corporation's rates effective November 1, 2015 and an additional 2% reduction in Supply Corporation's rates effective November 1, 2016, both of which were required by the rate case settlement approved by FERC on November 13, 2015. The decrease also reflects reductions in Empire's rates effective July 1, 2016 as required by the rate case settlement approved by FERC on December 13, 2016 combined with a decline in demand charges for transportation services as a result of contract terminations and contract restructuring, as well as lower demand for short-term interruptible transportation service. Partially offsetting these decreases, transportation revenues benefited from a full year of revenue from Supply Corporation's Northern Access 2015 project, which was placed in service on an interim basis in November 2015 and became fully operational in December 2015, and transportation revenues also benefited from a full year of revenue from Empire's Tuscarora Lateral Project, which was placed in service in November 2015.

Transportation volume increased by 20.8 Bcf in 2017 as compared with 2016. The increase in transportation volume primarily reflects the impact of a full year of transportation service from the Northern Access 2015 project and the Tuscarora Lateral Project, both of which are discussed in the previous paragraph.

Earnings

2018 Compared with 2017

The Pipeline and Storage segment’s earnings in 2018 were $97.2 million, an increase of $28.8 million when compared with earnings of $68.4 million in 2017. The increase in earnings was primarily due to lower income tax expense ($25.8 million) combined with the earnings impact of higher transportation and storage revenues of $3.6 million, as discussed above, a decrease in interest expense ($1.5 million) and lower operating expenses ($0.4 million). Income tax expense was lower due to the remeasurement of accumulated deferred income taxes in the quarter ended December 31, 2017 ($14.1 million) combined with the current period earnings impact of the change in the federal tax rate from 35% to a blended rate of 24.5% for fiscal 2018 ($11.7 million), both a result of the 2017 Tax Reform Act. The decrease in operating expenses primarily reflects lower pension and other post-retirement benefit costs partially offset by an increase in pipeline integrity program expenses, increase in compressor station costs and increased personnel costs. The decrease in interest expense was largely due to lower intercompany long-term borrowing interest rates for the Pipeline and Storage segment. These earnings contributors were slightly offset by higher income tax expense ($0.7 million) excluding the impact of the 2017 Tax Reform Act, an increase in depreciation expense ($1.5 million) and an increase in property taxes ($0.8 million). The increase in income taxes was a result of higher state taxes combined with a reduction in benefits associated with the tax sharing agreement with affiliated companies. The increase in depreciation expense was due to incremental depreciation expense related to expansion projects that were placed in service within the last year combined with the non-recurrence of a reduction to depreciation expense recorded in the quarter ended December 31, 2016 to reflect a reduction in depreciation rates retroactive to July 1, 2016 in accordance with Empire's rate case settlement. The FERC issued an order approving the settlement on December 13, 2016.

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

2017 Compared with 2016

The Pipeline and Storage segment’s earnings in 2017 were $68.4 million, a decrease of $8.2 million when compared with earnings of $76.6 million in 2016. The decrease in earnings was primarily due to the earnings impact of lower transportation revenues of $6.9 million, as discussed above, combined with higher operating expenses ($4.4 million), an increase in property taxes ($0.8 million) and a decrease in the allowance for funds used during construction (equity component) of $0.5 million. The increase in operating expenses primarily reflected an increase in compressor station costs due primarily to costs associated with the overhaul of two compressor stations, higher pension and other post-retirement benefit costs and increased personnel costs. The decrease in

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allowance for funds used during construction reflected the completion of Supply Corporation’s Westside Expansion and Modernization Project, Supply Corporation's Northern Access 2015 project and Empire's Tuscarora Lateral Project in the first quarter of fiscal 2016. These earnings decreases were partially offset by a decrease in depreciation expense ($1.4 million) and lower income tax expense ($3.2 million). The decrease in depreciation expense was attributable to a decrease in Empire's depreciation rates associated with Empire's rate case settlement as discussed above offset partially by the incremental depreciation expense related to expansion projects that were placed in service within the last year. Income tax expense was lower due to provision-to-return adjustments combined with lower state taxes, an increase in benefits associated with the tax sharing agreement with affiliated companies and the adoption of the accounting guidance regarding stock-based compensation.

GATHERING

Revenues

Gathering Operating Revenues

	Year Ended September 30		
	2018	2017	2016
	(Thousands)		
Gathering	$107,856	$107,566	$89,073
Processing and Other Revenues	41	115	374
	$107,897	$107,681	$89,447

Gathering Volume — (MMcf)

	Year Ended September 30		
	2018	2017	2016
Gathered Volume	198,355	194,921	161,955

2018 Compared with 2017

Operating revenues for the Gathering segment increased $0.2 million in 2018 as compared with 2017. This slight increase was primarily due to an increase in gathered volume at Midstream Company's Covington, Trout Run, Clermont and Wellsboro gathering systems, largely offset by the net impact of changes made to rates charged by the Covington, Trout Run and Wellsboro gathering systems and the impact of the sale of the Mt. Jewett, Owls Nest and Tionesta gathering systems. The gathering systems at Covington, Trout Run, Clermont and Wellsboro had a combined net increase in gathered volume of 4.3 Bcf year over year, increasing revenues by $2.1 million. The 4.3 Bcf increase in gathered volume can be attributed to the net increase in Seneca's production. The change in gathering rates and the sale of the Mt. Jewett, Owls Nest and Tionesta gathering systems, all of which occurred in the second quarter of fiscal 2018, reduced operating revenues year over year by $1.1 million and $0.8 million, respectively.

2017 Compared with 2016

Operating revenues for the Gathering segment increased $18.2 million in 2017 as compared with 2016. This increase was due to an increase in gathering revenues driven by a 33.0 Bcf increase in gathered volume. The overall increase in gathered volume was due to a 22.5 Bcf increase in gathered volume on Clermont, a 4.7 Bcf increase in gathered volume on Wellsboro, a 3.0 Bcf increase in gathered volume on Trout Run and a 2.9 Bcf increase in gathered volume on Covington. The increases in the aforementioned volumes were largely due to increases in Seneca's Marcellus Shale production due to a significant decrease in price-related curtailments during fiscal 2017 compared to fiscal 2016.

Earnings

2018 Compared with 2017

The Gathering segment’s earnings in 2018 were $83.5 million, an increase of $43.1 million when compared with earnings of $40.4 million in 2017. The increase in earnings was primarily attributable to lower income tax expense driven largely by the impact of the 2017 Tax Reform Act, which resulted in the remeasurement of accumulated deferred taxes ($34.5 million) and reduced the Company's federal tax rate resulting in lower income tax expense on current year earnings ($8.0 million). Additionally, tax planning and restructuring activities implemented during the year reduced the Gathering segment's deferred state income taxes and increased current year earnings ($2.3 million). These earnings increases were offset by higher operating expenses ($1.8 million) and higher depreciation expense ($0.7 million). The increase in operating expenses was due largely to the operation of new compression facilities along the Covington gathering system that were acquired from affiliate Seneca in March 2018, an increase in facilities and maintenance activity at the Clermont and Trout Run gathering systems, and a loss recognized on the sale of pipe materials. Depreciation expense increased due to higher plant balances, primarily for the Clermont and Trout Run gathering systems.

2017 Compared with 2016

The Gathering segment’s earnings in 2017 were $40.4 million, an increase of $9.9 million when compared with earnings of $30.5 million in 2016. The increase in earnings was mainly due to an increase in gathering revenues ($12.0 million). The increase in gathering revenues was due to the increases in gathered volume discussed above. These were partially offset by higher operating expenses ($1.8 million) and higher depreciation expense ($0.6 million). The increase in operating expenses were largely due to the ramp up in gathering operations as a result of increases in Seneca's Marcellus Shale production. An increase in gas plant balances (mostly in Clermont), led to an increase in depreciation expense.

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2018	2017	2016
	(Thousands)		
Retail Revenues:			
Residential	$487,344	$435,357	$360,648
Commercial	67,134	58,988	44,994
Industrial	4,090	2,376	1,785
	558,568	496,721	407,427
Off-System Sales	358	3,997	1,877
Transportation	129,909	129,509	124,120
Other	(1,309)	9,744	10,723
	$687,526	$639,971	$544,147

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2018	2017	2016
Retail Sales:			
Residential	60,174	52,394	49,971
Commercial	9,187	7,927	7,247
Industrial	623	333	244
	69,984	60,654	57,462
Off-System Sales	141	1,301	1,243
Transportation	76,828	71,040	70,847
	146,953	132,995	129,552

Degree Days

Year Ended September 30		Normal		Actual	Percent (Warmer) Colder Than Normal(1)	Prior Year(1)
2018	Buffalo	6,617		6,391	(3.4)%	12.0 %
	Erie	6,147		5,976	(2.8)%	15.4 %
2017	Buffalo	6,617		5,708	(13.7)%	1.7 %
	Erie	6,147		5,179	(15.7)%	(0.1)%
2016	Buffalo	6,653	(2)	5,611	(15.7)%	(19.5)%
	Erie	6,181	(2)	5,182	(16.2)%	(21.3)%

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

(2) Normal degree day estimates changed to 6,653 for Buffalo and 6,181 for Erie as a result of updated information from the National Oceanic and Atmospheric Administration. In addition, normal degree days for 2016 reflect the fact that 2016 was a leap year.

2018 Compared with 2017

Operating revenues for the Utility segment increased $47.6 million in 2018 compared with 2017. The increase largely resulted from a $61.8 million increase in retail gas sales revenues. The increase in retail gas sales revenues was largely a result of higher volumes (due to colder weather) and an increase in the cost of gas sold (per Mcf). These increases were partially offset by a $3.6 million decrease in off-system sales (due to lower volumes) and an $11.1 million decrease in other revenues. Due to profit sharing with retail customers, the margins related to off-system sales are minimal. The $11.1 million decrease in other revenues was largely due to a $12.7 million refund provision recorded during 2018 to refund the net effect of the reduction in the federal income tax rate resulting from the 2017 Tax Reform Act to the Utility segment's customers in accordance with NYPSC and PaPUC regulatory orders.

2017 Compared with 2016

Operating revenues for the Utility segment increased $95.8 million in 2017 compared with 2016. The increase largely resulted from an $89.3 million increase in retail gas sales revenues. In addition, there was a $5.4 million increase in transportation revenues, and a $2.1 million increase in off-system sales (due to higher sales prices coupled with slightly higher volumes). Due to profit sharing with retail customers, the margins related to off-system sales are minimal. The increase in retail gas sales revenues was largely a result of an increase in the cost of gas sold (per Mcf) coupled with an increase in volumes due to higher usage. The increase in transportation revenues was due to the increase in the price paid by marketers to cash-out their imbalances and an increase in those imbalances owed to the Utility segment as transportation throughput was relatively flat.

Purchased Gas

The cost of purchased gas is the Company’s single largest operating expense. Annual variations in purchased gas costs are attributed directly to changes in gas sales volume, the price of gas purchased and the operation of purchased gas adjustment clauses. Distribution Corporation recorded $306.1 million, $252.8 million and $166.2 million of Purchased Gas expense during 2018, 2017 and 2016, 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,

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such costs do not impact the profitability of the Company. Purchased gas costs impact cash flow from operations due to the timing of recovery of such costs versus the actual purchased gas costs incurred during a particular period. Distribution Corporation's purchased gas adjustment clauses seek to mitigate this impact by adjusting revenues on either a quarterly or monthly basis.

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

Earnings

2018 Compared with 2017

The Utility segment's earnings in 2018 were $51.2 million, an increase of $4.3 million when compared with earnings of $46.9 million in 2017. Higher earnings associated with the new rate order issued by the NYPSC effective April 1, 2017 ($2.8 million), the impact of colder weather in fiscal 2018 compared to fiscal 2017 ($5.2 million), lower interest expense ($1.1 million) and a decrease in property and other taxes ($0.7 million) were partially offset by the impact of regulatory adjustments ($3.9 million), higher operating expenses ($1.8 million) and the net impact of the 2017 Tax Reform Act, as discussed below. Lower earnings associated with regulatory adjustments are largely due to changes in the low income customer discount and payment assistance program implemented in the Utility segment's New York rate jurisdiction after the new rate order became effective on April 1, 2017. The increase in operating expenses is primarily due to higher amortization of environmental remediation costs that resulted from the new rate order combined with higher personnel costs and bad debt expense, partially offset by lower pension and other post-retirement benefit costs. The decrease in interest expense was largely due to lower interest rates on intercompany long-term borrowings.

The 2017 Tax Reform Act lowered the Company's statutory federal income tax rate, which resulted in lower income tax expense on the Utility segment's fiscal 2018 earnings ($7.8 million). The positive impact of the lower income taxes, however, was offset by a refund provision recorded during the year to refund the net effect of the lower federal income tax rate to the Utility segment's customers in accordance with NYPSC and PaPUC regulatory orders. The refund provision, which reduced other operating revenues, lowered earnings by $8.2 million.

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. For 2018, the WNC increased earnings by approximately $0.2 million, as the weather was warmer than normal. In 2017, the WNC increased earnings by approximately $4.3 million, as the weather was warmer than normal.

2017 Compared with 2016

The Utility segment's earnings in 2017 were $46.9 million, a decrease of $4.1 million when compared with earnings of $51.0 million in 2016. The decrease in earnings was largely attributable to higher operating expenses of $3.3 million (primarily due to higher personnel costs including the impact of post-implementation costs related to the replacement of the Utility segment's legacy mainframe system), higher depreciation expense of $2.6 million (largely due to higher plant balances including the impact of the legacy mainframe system replacement), a decrease in the allowance for funds used during construction (equity component) of $0.9 million (due to the May 2016 completion of the Utility segment's legacy mainframe system), higher income tax expense of $0.9 million (largely due to the aforementioned reduction in the allowance for funds used during construction in the current year which is non-taxable), lower interest income of $0.6 million (due to a lower balance in a regulatory asset and its impact on accrued income) and higher interest expense of $0.6 million (largely due to the impact of a regulatory adjustment coupled with a reduction in the allowance for borrowed funds used during construction due to the May 2016 completion of the Utility segment's legacy mainframe system). These were partially offset by the positive earnings impact associated with higher usage ($2.5 million) and the impact of regulatory adjustments ($1.9 million, including

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the $1.5 million margin impact related to the new rate order issued by the NYPSC effective April 1, 2017). Usage refers to consumption after factoring out any impact that weather may have had on consumption.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2018	2017	2016
	(Thousands)		
Natural Gas (after Hedging)	$138,531	$129,317	$94,028
Other	43	63	434
	$138,574	$129,380	$94,462

Energy Marketing Volume

	Year Ended September 30		
	2018	2017	2016
Natural Gas — (MMcf)	42,262	38,901	39,849

2018 Compared with 2017

Operating revenues for the Energy Marketing segment increased $9.2 million in 2018 as compared with 2017. The increase was primarily a result of an increase in gas sales revenue due to an increase in volume sold to retail customers as a result of colder weather and additional business from new customers, partially offset by a lower average price of natural gas period over period.

2017 Compared with 2016

Operating revenues for the Energy Marketing segment increased $34.9 million in 2017 as compared with 2016. The increase was primarily due to an increase in gas sales revenue due to a higher average price of natural gas period over period, slightly offset by a decrease in volume sold to retail customers.

Earnings

2018 Compared with 2017

The Energy Marketing segment's earnings in 2018 were $0.4 million, a decrease of $1.1 million when compared with earnings of $1.5 million in 2017. This decrease in earnings was primarily attributable to lower margin of $1.3 million and higher income tax expense of $0.3 million. The decrease in margin largely reflects a decline in average margin per Mcf primarily due to stronger natural gas prices at local purchase points relative to NYMEX-based sales contracts. Income tax expense was higher primarily due to a remeasurement of accumulated deferred income taxes ($0.4 million), partially offset by a decline in current period income taxes as a result of the reduction in the federal tax rate from 35% to a blended rate of 24.5% ($0.1 million), both a result of the 2017 Tax Reform Act. The earnings decrease was slightly offset by lower operating expenses of $0.3 million, which primarily reflects lower pension costs and a decrease in advertising expenses.

2017 Compared with 2016

The Energy Marketing segment's earnings in 2017 were $1.5 million, a decrease of $2.8 million when compared with earnings of $4.3 million in 2016. This decrease in earnings was primarily attributable to lower margin of $2.6 million. The decrease in margin largely reflected a decline in average margin per Mcf primarily due to stronger natural gas prices at local purchase points relative to NYMEX-based sales contracts, combined with the margin impact associated with the decrease in volume sold to retail customers during the year ended September 30, 2017 compared to the year ended September 30, 2016.

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 markets timber from its New York and Pennsylvania land holdings.

Earnings

2018 Compared with 2017

All Other and Corporate operations recorded a loss of $21.5 million in 2018, which was $18.4 million higher than the loss of $3.1 million in 2017. The increase in loss was primarily attributable to higher income tax expense ($19.1 million) and higher depreciation expense ($0.6 million). The increase in income tax expense was driven largely by the impact of the 2017 Tax Reform Act, which resulted in a remeasurement of accumulated deferred taxes ($18.4 million) and lowered the Company's federal tax rate, reducing the income tax benefit realized on the current year loss ($0.7 million). These decreases in earnings were partially offset by higher margins ($1.6 million) from the sale of standing timber by Seneca's Northeast division.

2017 Compared with 2016

All Other and Corporate operations recorded a loss of $3.1 million in 2017, which was $2.6 million higher than the loss of $0.5 million in 2016. The increase in loss was primarily due to higher operating expenses ($1.2 million) largely due to higher personnel costs, higher income tax expense ($0.5 million) and lower margins ($1.0 million) from the sale of standing timber by Seneca’s Northeast division.

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 $5.5 million in 2018 as compared to 2017. This decrease was primarily due to a decrease in the weighted average interest rate on long-term debt outstanding. The Company issued $300 million of 4.75% notes in August 2018 and $300 million of 3.95% notes in September 2017. The Company repaid $250 million of 8.75% notes in September 2018 and $300 million of 6.50% notes in October 2017.

Interest on long-term debt decreased $0.9 million in 2017 as compared to 2016. This decrease was primarily due to an increase in the capitalization of interest costs (mostly in Midstream Company) which decreased interest expense for the year ended September 30, 2017 as compared to the year ended September 30, 2016.

CAPITAL RESOURCES AND LIQUIDITY

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

	Year Ended September 30		
	2018	2017	2016
	(Millions)		
Provided by Operating Activities	$613.6	$684.3	$589.0
Capital Expenditures	(584.0)	(450.3)	(581.6)
Net Proceeds from Sale of Oil and Gas Producing Properties	55.5	26.6	137.3
Other Investing Activities	(0.3)	1.2	(9.2)
Reduction of Long-Term Debt	(566.5)	—	—
Net Proceeds from Issuance of Long-Term Debt	295.0	295.2	—
Net Proceeds from Issuance of Common Stock	4.1	7.7	13.8
Dividends Paid on Common Stock	(143.3)	(139.1)	(134.8)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	—	—	1.9
Net Increase (Decrease) in Cash and Temporary Cash Investments	$(325.9)	$425.6	$16.4

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, deferred income taxes and stock-based compensation.

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

Cash provided by operating activities in the Exploration and Production segment may vary from year to year as a result of changes in the commodity prices of natural gas and crude oil as well as changes in production. The Company uses various derivative financial instruments, including price swap agreements and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $613.6 million in 2018, a decrease of $70.7 million compared with the $684.3 million provided by operating activities in 2017. The decrease in cash provided by operating activities primarily reflects lower cash provided by operating activities in the Exploration and Production segment partially offset by an increase in cash provided by operating activities in the Utility segment. The decrease in the Exploration and Production segment was primarily due to lower cash receipts as a result of lower natural gas prices realized from natural gas production. The increase in the Utility segment was primarily due to the timing of gas cost recovery.

Net cash provided by operating activities totaled $684.3 million in 2017, an increase of $95.3 million compared with the $589.0 million provided by operating activities in 2016. The increase in cash provided by operating activities reflected higher cash provided by operating activities in the Exploration and Production and Gathering segments primarily due to higher cash receipts from natural gas production and gathering services in the Appalachian region.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company’s expenditures for long-lived assets, including non-cash capital expenditures, totaled $600.6 million, $462.1 million and $523.1 million in 2018, 2017 and 2016, respectively. The table below presents these expenditures:

	Year Ended September 30					
	2018		2017		2016	
	(Millions)					
Exploration and Production:						
Capital Expenditures(4)	$380.7	(1)	$253.1	(2)	$256.1	(3)
Pipeline and Storage:						
Capital Expenditures	92.8	(1)	95.3	(2)	114.3	(3)
Gathering:						
Capital Expenditures	61.7	(1)	32.6	(2)	54.3	(3)
Utility:						
Capital Expenditures	85.7	(1)	80.9	(2)	98.0	(3)
All Other and Corporate:						
Capital Expenditures	0.2		0.2		0.4	
Eliminations	(20.5)		—		—	
Total Expenditures	$600.6		$462.1		$523.1	

(1) 2018 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $51.3 million, $21.9 million, $6.1 million and $9.5 million, respectively, of non-cash capital expenditures.

(2) 2017 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $36.5 million, $25.1 million, $3.9 million and $6.7 million, respectively, of non-cash capital expenditures.

(3) 2016 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $25.2 million, $18.7 million, $5.3 million and $11.2 million, respectively, of non-cash capital expenditures.

(4) The capital expenditures for the Exploration and Production segment for 2018, 2017 and 2016 do not include any proceeds received from the sale of oil and gas assets to IOG under the joint development agreement.

Exploration and Production

In 2018, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $353.5 million for the Appalachian region (including $240.8 million in the Marcellus Shale area and $99.1 million in the Utica Shale area) and $27.2 million for the West Coast region. These amounts included approximately $182.3 million spent to develop proved undeveloped reserves.

The Company entered into a purchase and sale agreement to sell its oil and gas properties in the Sespe Field area of Ventura County, California in October 2017 for $43 million. The Company completed the sale on May 1, 2018, effective as of October 1, 2017, receiving net proceeds of $38.2 million (included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statement of Cash Flows for the year ended September 30, 2018). The net proceeds received by the Company were adjusted for production revenue and production expenses retained by the Company between the effective date of the sale and the closing date, resulting in lower proceeds from sale at the closing date. The divestiture of the Company’s oil and gas properties in the Sespe Field reflects continuing efforts to focus West Coast development activities in the San Joaquin basin, particularly at the Midway Sunset field in Kern County, California. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

On December 1, 2015, Seneca and IOG CRV - Marcellus, LLC (IOG), an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC, executed a joint development agreement that allows IOG to participate in the development of certain oil and gas interests owned by Seneca in Elk, McKean and Cameron Counties, Pennsylvania. On June 13, 2016, Seneca and IOG executed an extension of the joint development agreement. Under the terms of the extended agreement, Seneca and IOG jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. IOG holds an 80% working interest in all of the joint development wells. In total, IOG has funded $305.5 million as of September 30, 2018 for its 80% working interest in the 75 joint development wells, which includes $181.2 million of cash ($137.3 million in fiscal 2016, $26.6 million in fiscal 2017 and $17.3 million in fiscal 2018) included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statements of Cash Flows for fiscal 2016, fiscal 2017 and fiscal 2018, respectively. Such proceeds from sale represent funding received from IOG for costs previously incurred by Seneca to develop a portion of the 75 joint development wells. For further discussion of the extended joint development agreement, refer to Item 8 at Note A — Summary of Significant Accounting Policies under the heading “Property, Plant and Equipment.”

In 2017, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $213.8 million for the Appalachian region (including $168.2 million in the Marcellus Shale area) and $39.3 million for the West Coast region. These amounts included approximately $101.1 million spent to develop proved undeveloped reserves.

In 2016, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $217.3 million for the Appalachian region (including $201.8 million in the Marcellus Shale area) and $38.8 million for the West Coast region. These amounts included approximately $92.8 million spent to develop proved undeveloped reserves.

On June 30, 2016, Seneca sold the majority of its Upper Devonian wells in Pennsylvania. While the proceeds from the sale were not significant, it did result in a $58.4 million reduction of its Asset Retirement Obligation for the year ended September 30, 2016.

Pipeline and Storage

The majority of the Pipeline and Storage segment’s capital expenditures for 2018 were related to additions, improvements and replacements to this segment’s transmission and gas storage systems. In addition, the Pipeline and Storage segment capital expenditures for 2018 include expenditures related to Supply Corporation's Line D Expansion project ($14.5 million), as discussed below.

The majority of the Pipeline and Storage segment’s capital expenditures for 2017 were related to additions, improvements and replacements to this segment’s transmission and gas storage systems. In addition, the Pipeline and Storage segment capital expenditures for 2017 included expenditures related to Empire and Supply Corporation's Northern Access project ($22.1 million) and Supply Corporation's Line D Expansion project ($14.4 million).

The majority of the Pipeline and Storage segment’s capital expenditures for 2016 were mainly for expenditures related to Empire and Supply Corporation's Northern Access project ($26.7 million), Supply Corporation's Northern Access 2015 project ($13.1 million), Supply Corporation's Westside Expansion and Modernization project ($11.1 million), Supply Corporation's Line D Expansion project ($10.4 million) and Empire and Supply Corporation's Tuscarora Lateral project ($7.6 million). In addition, the Pipeline and Storage segment capital expenditures for 2016 also 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 2018 were for the purchase of two compressor stations for Midstream Company's Covington Gathering System as well as the continued buildout of Midstream Company's Trout Run Gathering System and Midstream Company's Clermont Gathering System, both of which are discussed below. Midstream Company spent $27.0 million and $14.8 million, respectively, in 2018 on the development of the Trout Run and Clermont gathering systems.

The majority of the Gathering segment's capital expenditures for 2017 and 2016 were for the construction and/or continued buildout of Midstream Company's Clermont Gathering System. Midstream Company spent $21.7 million in 2017 and $43.2 million in 2016 for the development of this system.

Utility

The majority of the Utility segment's capital expenditures for 2018, 2017 and 2016 were made for main and service line improvements and replacements, as well as main extensions. The capital expenditures for 2016 included $16.4 million related to the replacement of the Utility segment's customer information system, which was placed in service in May 2016.

Estimated Capital Expenditures

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

	Year Ended September 30		
	2019	2020	2021
	(Millions)		
Exploration and Production(1)	$480	$510	$485
Pipeline and Storage	135	225	275
Gathering	60	75	45
Utility	95	95	95
All Other	—	—	—
	$770	$905	$900

(1) Includes estimated expenditures for the years ended September 30, 2019, 2020 and 2021 of approximately $210 million, $123 million and $64 million, respectively, to develop proved undeveloped reserves. The Company is committed to developing its proved undeveloped reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting.

Exploration and Production

Estimated capital expenditures in 2019 for the Exploration and Production segment include approximately $445 million for the Appalachian region and $35 million for the West Coast region.

Estimated capital expenditures in 2020 for the Exploration and Production segment include approximately $465 million for the Appalachian region and $45 million for the West Coast region.

Estimated capital expenditures in 2021 for the Exploration and Production segment include approximately $450 million for the Appalachian region and $35 million for the West Coast region.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2019 through 2021 are expected to include: construction of new pipeline and compressor stations to support expansion projects, the replacement of transmission and storage lines, the reconditioning of storage wells and improvements of compressor stations. Expansion projects where the Company has begun to make significant investments of preliminary survey and investigation costs and/or where shipper agreements have been executed are described below.

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

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

Supply Corporation and Empire are developing a project which would move significant prospective Marcellus production from Seneca's Western Development Area at Clermont to an Empire interconnection with TransCanada Pipeline at Chippawa and an interconnection with TGP's 200 Line in East Aurora, New York (the "Northern Access project"). The Northern Access project would provide an outlet to Dawn-indexed markets in Canada and to the TGP line serving the U.S. Northeast. The Northern Access project involves the construction of approximately 99 miles of largely 24" pipeline and approximately 27,500 horsepower of compression on the two systems. Supply Corporation, Empire and Seneca executed anchor shipper agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa and 140,000 Dth per day of firm transportation capacity to a new interconnection with TGP's 200 Line on this project. On February 3, 2017, the Company received FERC approval of the project. On April 7, 2017, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received on January 27, 2017). On April 21, 2017, the Company appealed the NYDEC's decision with regard to the Water Quality Certification to the United States Court of Appeals for the Second Circuit, and on May 11, 2017, the Company commenced legal action in New York State Supreme Court challenging the NYDEC's actions with regard to various state permits. On August 6, 2018, the FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. Rehearing requests have been filed at FERC. The Company remains committed to the project. In light of these pending legal actions and the need to complete necessary project development activities in advance of construction, the target in-service date for the project is expected to be no earlier than the first half of fiscal 2022. The Company will update the $500 million preliminary cost estimate when there is further clarity on that date. As of September 30, 2018, approximately $76.2 million has been spent on the Northern Access project, including $23.0 million that has been spent to study the project, for which no reserve has been established. The remaining $53.2 million spent on the project has been capitalized as Construction Work in Progress.

On November 21, 2014, Supply Corporation concluded an Open Season for an expansion of its Line D pipeline ("Line D Expansion") that is intended to allow growing on-system markets to avail themselves of economical gas supply on the TGP 300 line, at an existing interconnect at Lamont, Pennsylvania, and provide increased capacity into the Erie, Pennsylvania market area. Supply Corporation has executed Service Agreements for a total of 77,500 Dth per day for terms of six to ten years and services began November 1, 2017. The project included construction of a new 4,140 horsepower Keelor Compressor Station and modifications to the Bowen compressor station. The project also provides system modernization benefits. As of September 30, 2018, approximately $29.0 million has been spent on the Line D Expansion project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2018.

Empire concluded an Open Season on November 18, 2015, and has designed a project that would allow for the transportation of 205,000 Dth per day of additional shale supplies from interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline, and the TGP 200 Line ("Empire North Project"). This project is fully subscribed under long term agreements. Empire filed a Section 7(c) application with the FERC in February 2018. The Empire North Project has a projected in-service date in the second half of fiscal 2020 and an estimated capital cost of approximately $145 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2018, approximately $4.3 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at September 30, 2018.

Supply Corporation has entered into a foundation shipper Precedent Agreement to provide incremental natural gas transportation services from Line N to the ethane cracker facility being constructed by Shell Chemical Appalachia, LLC in Potter Township, Pennsylvania. Supply Corporation has completed an Open Season for the project and has secured incremental firm transportation capacity commitments totaling 133,000 Dth per day on Line N and on the proposed pipeline extension of approximately 4.5 miles from Line N to the facility. Supply Corporation filed a prior notice application with FERC on March 23, 2018 and was authorized to pursue the project under its blanket certificate as of May 30, 2018. The proposed in-service date for this project is as early as July 1, 2019 at an estimated capital cost of approximately $23 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2018, approximately $2.2 million has been capitalized as Construction Work in Progress for this project.

Supply Corporation is currently in the pre-filing process at FERC for its FM100 Project, which will upgrade 1950's era pipeline in northwestern Pennsylvania and create approximately 330,000 Dth per day of additional capacity on its system 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. A precedent agreement has been executed by Supply Corporation and Transco whereby this additional capacity is expected to be leased by Transco, and will be part of the capacity Transco will offer in connection with its Leidy South expansion project that will make available capacity from receipt points along its Leidy Line to Zone 6 markets. Seneca will be an anchor shipper on Transco’s project, providing Seneca with an outlet to premium markets for its Marcellus and Utica production from both the Clermont-Rich Valley and Trout Run-Gamble areas. The FM100 Project has a target in-service date in late calendar 2021 and a preliminary cost estimate of approximately $280 million. The majority of these expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above, with a small amount of the expenditures estimated to extend into fiscal 2022. As of September 30, 2018, approximately $1.4 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at September 30, 2018.

Gathering

The majority of the Gathering segment capital expenditures in 2019 through 2021 are expected to be for construction and expansion of gathering systems, as discussed below.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Company, is building an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The total cost estimate for the continued buildout will be dependent on the nature and timing of Seneca's long-term plans. Estimated capital expenditures in 2019 through 2021 include anticipated expenditures in the range of $40 million to $70 million for the continued expansion of the Clermont Gathering System. As of September 30, 2018, the Company has spent approximately $296.1 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2018.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Company, continues to develop its Trout Run Gathering System in Lycoming County, Pennsylvania. The Trout Run Gathering System was initially placed in service in May 2012. The current system consists of approximately 48 miles of backbone and in-field gathering pipelines, two compressor stations and a dehydration and metering station. Estimated capital expenditures in 2019 through 2021 include anticipated expenditures in the range of $50 million to $90 million for the continued expansion of the Trout Run Gathering System. As of September 30, 2018, the Company has spent approximately $204.4 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2018.

NFG Midstream Wellsboro, LLC, a wholly owned subsidiary of Midstream Company, continues to develop its Wellsboro Gathering System in Tioga County, Pennsylvania. Estimated capital expenditures in 2019 through 2021 include anticipated expenditures in the range of $40 million to $70 million for the continued expansion of the Wellsboro Gathering System. The Company has spent approximately $9.4 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2018.

Utility

Capital expenditures for the Utility segment in 2019 through 2021 are expected to be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment.

Project Funding

Over the past two years, the Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations as well as proceeds received from the sale of oil and gas assets. Going forward, while the Company expects to use cash on hand and cash from operations as the first means of financing these projects, the Company may issue short-term and/or long-term debt as necessary during fiscal 2019 to help meet its capital expenditures needs. The level of short-term and long-term borrowings will depend upon the amount of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells.

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

FINANCING CASH FLOW

The Company did not have any consolidated short-term debt outstanding at September 30, 2018 or September 30, 2017, nor was there any short-term debt outstanding during the year ended September 30, 2018. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt.

On October 25, 2018, the Company entered into a Fourth Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of 12 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through October 25, 2023. The Company also has an uncommitted line of credit with a financial institution for general corporate purposes. Borrowings under this uncommitted line of credit would be made at competitive market rates. The uncommitted credit line is revocable at the option of the financial institution and is reviewed on an annual basis. The Company anticipates that its uncommitted line of credit generally will be renewed or substantially replaced by a similar line. Other financial institutions may also provide the Company with uncommitted or discretionary lines of credit in the future.

The total amount available to be issued under the Company's commercial paper program is $500.0 million. The commercial paper program is backed by the Credit Agreement, which provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter. For purposes of calculating the debt to capitalization ratio, the Company's total capitalization will be increased by adding back 50% of the aggregate after-tax amount of non-cash charges directly arising from any ceiling test impairment occurring on or after July 1, 2018, not to exceed $250 million. At September 30, 2018, the Company's debt to capitalization ratio (as calculated under the facility) was .52. The constraints specified in the Credit Agreement would have permitted an additional $1.46 billion in short-term and/or long-term debt to be outstanding at September 30, 2018 (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

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

However, the Company expects that it could borrow under its credit facilities or rely upon other liquidity sources, including cash provided by operations.
The Credit Agreement contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2018, the Company did not have any debt outstanding under the Credit Agreement.
On August 17, 2018, the Company issued $300.0 million of 4.75% notes due September 1, 2028. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $295.0 million. The 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 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 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 subs