NATIONAL FUEL GAS CO
Form 10-K
November 21, 2014

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, 2014

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

For the Transition Period from to
Commission File Number 1-3880
National Fuel Gas Company
(Exact name of registrant as specified in its charter)

New Jersey	13-1086010
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
6363 Main Street Williamsville, New York (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 and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted 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 and post 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, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):
Large accelerated filer þ Accelerated filer ¨ Non-accelerated filer ¨ Smaller reporting company ¨

(Do not check if a smaller reporting company)

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 $5,688,675,000 as of March 31, 2014.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2014: 84,190,266 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2015 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2014, 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.

ESNE Energy Systems North East, LLC

Horizon Power Horizon Power, Inc.

Midstream Corporation National Fuel Gas Midstream Corporation

National Fuel National Fuel Gas Company

NFR National Fuel Resources, Inc.

Registrant National Fuel Gas Company

Seneca Seneca Resources Corporation

Supply Corporation National Fuel Gas Supply Corporation

Regulatory Agencies

CFTC Commodity Futures Trading Commission

EPA United States Environmental Protection Agency

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

NYDEC New York State Department of Environmental Conservation

NYPSC State of New York Public Service Commission

PaDEP Pennsylvania Department of Environmental Protection

PaPUC Pennsylvania Public Utility Commission

PHMSA Pipeline and Hazardous Materials Safety Administration

SEC Securities and Exchange Commission

Other

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.
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, 2014
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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 model centered in western New York and Pennsylvania, an area critical to the production and transportation of natural gas from the Marcellus Shale basin. 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 Marcellus Shale 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 Corporation (Seneca), a Pennsylvania corporation. Seneca is engaged in the exploration for, and the development and production of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in Kansas. At September 30, 2014, Seneca had U.S. proved developed and undeveloped reserves of 38,477 Mbbl of oil and 1,682,884 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) 27 underground natural gas storage fields owned and operated by Supply Corporation as well as four other underground natural gas storage fields owned and operated jointly with other interstate gas pipeline companies. Empire, an interstate pipeline company, transports natural gas for Distribution Corporation and for other utilities, large industrial customers and power producers in New York State. Empire owns the Empire Pipeline, a 249-mile integrated pipeline system comprising three principal components: a legacy 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 76-mile pipeline extension from near Rochester, New York to an interconnection with the unaffiliated Millennium Pipeline near Corning, New York (the Empire Connector), and a 16-mile pipeline extension from Corning into Tioga County, Pennsylvania (the Tioga County Extension).

3. The Gathering segment operations are carried out by wholly-owned subsidiaries of National Fuel Gas Midstream Corporation (Midstream Corporation), a Pennsylvania corporation. Through these subsidiaries, Midstream Corporation 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 737,800 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.

The following business is not included in any of the five reported business segments:

- Seneca's Northeast Division, which markets timber from Appalachian land holdings. At September 30, 2014, the Company owned approximately 93,000 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 2014.

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 (including foreign) 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 40.6% of the Company's 2014 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 25.9% of the Company's 2014 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. Supply Corporation currently has firm transportation service agreements for approximately 2,674 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,035 MDth per day or 39% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 174 MDth per day or 7%. The remaining 1,465 MDth or 54% is subject to firm contracts with nonaffiliated customers. Contracted transportation capacity with both affiliated and unaffiliated shippers is expected to increase 4% in 2015.

Supply Corporation has service agreements for essentially all of its firm storage capacity, totaling 67,967 MDth. The Utility segment has contracted for 28,491 MDth or 42% of the total firm storage capacity, and the Energy Marketing segment accounts for another 3,097 MDth or 5%. Nonaffiliated customers have contracted for the remaining 36,379 MDth or 53%. Supply Corporation expects 2% of its contracted firm storage capacity to expire or terminate and be available for remarketing in 2015.

At the end of 2014, Empire had service agreements in place for firm transportation capacity totaling up to approximately 952 MDth per day, with 98% 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. None of the long-term contracts will expire or terminate in 2015.

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).

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 10.9% of the Company's 2014 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 21.4% of the Company's 2014 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 2.2% of the Company's 2014 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 2014. The impact of this net loss in relation to the Company's 2014 net income available for common stock was negative 1.0%.

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 M — Supplementary Information for Oil and Gas Producing Activities.

Supply Corporation transports and stores 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. Empire transports gas owned by its customers, whose gas originates in the Appalachian region 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 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 2014, the Utility segment purchased 71.0 Bcf of gas for delivery to its customers. 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 for one month or less) accounted for 48% of the Utility segment’s 2014 purchases. Purchases from South Jersey Resources Group, LLC (20%), Tenaska Marketing Ventures (13%), Statoil Natural Gas, LLC (9%) and DTE Energy Trading, Inc. (8%) accounted for 50% of the Utility’s 2014 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2014.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2014, this segment purchased 53.4 Bcf of gas, including 52.7 Bcf for delivery to its customers. The remaining 0.7 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 certain of 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 Shale production area in Pennsylvania. Its facilities are also located adjacent to Canada and the northeastern United States and provide part of the traditional link between gas-consuming regions of the eastern United States and gas-producing regions of Canada and the southwestern, southern and other continental regions of the United States. While costlier natural gas pricing at Niagara has decreased the importation and transportation of gas from that receipt point, new productive areas in the Appalachian region related to the development of the Marcellus Shale formation have increased transportation services from that region. Supply Corporation has developed its Northern Access and Line N pipeline expansion projects to receive natural gas produced from the Marcellus Shale and transport it to key markets of Canada and

the northeastern United States. For further discussion of these projects, refer to Item 7, MD&A under the headings "Investing Cash Flow" and "Rate and Regulatory Matters."

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. As noted above, the Empire Connector project expanded Empire's natural gas pipeline and enables Empire to serve new markets in New York and elsewhere in the Northeast. In November 2011, Empire also completed its Tioga County Extension project, which stretches approximately 16 miles south from its existing interconnection with Millennium Pipeline at Corning, New York, into Tioga County, Pennsylvania. Like Supply Corporation's Northern Access project, Empire's Tioga County Extension project facilitates transportation of Marcellus Shale gas to key markets of Canada and the northeastern United States.

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 23%, and in Pennsylvania, approximately 16%, 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. Over the longer run, it is possible that rate design changes resulting from further customer migration to marketer service could expose utility companies such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

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, competition continues with fuel oil suppliers. 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 or promote new uses of natural gas or new services, rates and contracts.

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 2,010 full-time employees at September 30, 2014.

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 2017. Agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2018 and May 2018.

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, 2014(1)

Name and Age (as of November 15, 2014)	Current Company Positions and Other Material Business Experience During Past Five Years
Ronald J. Tanski (62)	Chief Executive Officer of the Company since April 2013 and President of the Company since July 2010. Mr. Tanski previously served as Chief Operating Officer of the Company from July 2010 through March 2013; Treasurer and Principal Financial Officer of the Company from April 2004 through June 2010; and President of Supply Corporation from July 2008 through June 2010.
Matthew D. Cabell (56)	Senior Vice President of the Company since July 2010 and President of Seneca since December 2006.
Anna Marie Cellino (61)	President of Distribution Corporation since July 2008.
John R. Pustulka (62)	President of Supply Corporation since July 2010. Mr. Pustulka previously served as Senior Vice President of Supply Corporation from July 2001 through June 2010.
David P. Bauer (45)	Treasurer and Principal Financial Officer of the Company since July 2010; Treasurer of Midstream Corporation since April 2013; Treasurer of Supply Corporation since June 2007; Treasurer of Empire since June 2007; and Assistant Treasurer of Distribution Corporation since April 2004.
Karen M. Camiolo (55)	Controller and Principal Accounting Officer of the Company since April 2004; Controller of Midstream Corporation since April 2013; and Controller of Distribution Corporation and Supply Corporation since April 2004.
Carl M. Carlotti (59)	Senior Vice President of Distribution Corporation since January 2008.
Paula M. Ciprich (54)	Secretary of the Company since July 2008; General Counsel of the Company since January 2005; Secretary of Distribution Corporation since July 2008.
Donna L. DeCarolis (55)	Vice President Business Development of the Company since October 2007.
James D. Ramsdell (59)	Senior Vice President and Chief Safety Officer of the Company since May 2011. Mr. Ramsdell previously served as Senior Vice President of Distribution Corporation from July 2001 to May 2011.

(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 and negatively impact the availability of capital from banks, commercial paper purchasers and other sources.

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 and 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. 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 sometimes unpredictable 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 regulations that have an impact on almost every aspect of the Company's businesses. 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 or affect its business in ways that the Company cannot predict.

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.

In addition to their historical methods of utility regulation, both the PaPUC and NYPSC have established competitive markets in which customers may purchase gas commodity from unregulated marketers, in addition to utility companies. Retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation because in both jurisdictions it recovers its cost of service through delivery rates and charges, and not through any mark-up on the gas commodity purchased by its customers. Over the longer run, however, rate design changes resulting from further customer migration to marketer service ("unbundling") can expose utilities such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

Both the NYPSC and the PaPUC have instituted proceedings for the purpose of promoting conservation of energy commodities, including natural gas. In New York, Distribution Corporation implemented a Conservation Incentive Program that promotes conservation and efficient use of natural gas by offering customer rebates for high-efficiency appliances, among other things. The intent of conservation and efficiency programs is to reduce customer usage of natural gas. Under traditional volumetric rates, reduced usage by customers results in decreased revenues to the Utility. To prevent revenue erosion caused by conservation, the NYPSC approved a "revenue decoupling mechanism" that renders Distribution Corporation's New York division financially indifferent to the effects of conservation. In Pennsylvania, although a generic statewide proceeding is pending, the PaPUC has not yet directed Distribution Corporation to implement conservation measures. If the NYPSC were to revoke the revenue decoupling mechanism in a future proceeding or the PaPUC were to adopt a conservation program without a revenue decoupling mechanism or other changes in rate design, reduced customer usage could decrease revenues, forcing Distribution Corporation to file for rate relief. If Distribution Corporation were unable to obtain adequate rate relief, its financial condition, results of operations and cash flows would be adversely affected.

In New York, aggressive generic statewide programs created under the label of efficiency or conservation continue to generate a sizable utility funding requirement for state agencies that administer those programs. Although utilities are authorized to recover the cost of efficiency and conservation program funding through special rates and surcharges, the resulting upward pressure on customer rates, coupled with increased assessments and taxes, could affect future tolerance for traditional utility rate increases, especially if natural gas commodity costs were to increase.

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 reduce those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to reduce 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 from New York into Ontario.

In January 2012, President Obama signed into law the Pipeline Safety, Regulatory Certainty, and Job Creation Act. The legislation increases civil penalties for pipeline safety violations and addresses matters such as pipeline damage prevention, automatic and remote-controlled shut-off valves, excess flow valves, pipeline integrity management, documentation and testing of maximum allowable operating pressure, and reporting of pipeline accidents. The legislation requires the Pipeline and Hazardous Materials Safety Administration (PHMSA) to issue or revise certain regulations and to conduct various reviews, studies and evaluations. In addition, PHMSA in August 2011 issued an Advance Notice of Proposed Rulemaking regarding pipeline safety. As described in the notice, PHMSA is considering regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. Unrelated to these safety initiatives, the EPA in April 2010 issued an Advance Notice of Proposed Rulemaking reassessing its regulations governing the use and distribution in commerce of PCBs. The EPA had projected that it would issue a Notice of Proposed Rulemaking by April 2013, but it has not done so. 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 would be adversely affected.

In the Company's Exploration and Production segment, various aspects of Seneca's operations are subject to regulation by, among others, the EPA, the U.S. Fish and Wildlife Service, the U.S. Forestry Service, 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 the Oil and Gas Conservation Division of the Kansas Corporation Commission. Administrative proceedings or increased regulation by these or other agencies could lead to operational delays or restrictions and increased expense for Seneca.

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 pollutents, 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 control air emissions and 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 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.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. Under the Federal Clean Air Act, the EPA requires that new stationary sources of significant greenhouse gas emissions or major modifications of existing facilities obtain permits covering such emissions. The EPA is also considering other regulatory options to regulate greenhouse emissions from the energy industry. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts greenhouse gas emissions

could increase the Company's cost of environmental compliance by requiring the Company to install

new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas initiatives could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

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. 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 harms. These harms may require significant expenditures 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. These security incidents may have an adverse impact on the Company's operations, earnings and financial condition.

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 ability to finance capital expenditures and to refinance maturing debt.

The Company's ability to cost-effectively finance capital expenditures and to refinance maturing debt will depend in part upon interest rates. The direction in which interest rates may move is uncertain. Declining interest rates have generally been believed to be favorable to utilities, while rising interest rates are generally believed to be unfavorable, because of the levels of debt that utilities may have outstanding. 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 most of the oil and natural gas that it produces at current market and/or indexed prices rather than through fixed-price contracts, although as discussed below, the Company frequently hedges the price of a significant portion of its future production in 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.

The natural gas the Company produces is priced in local markets where production occurs, and price is therefore affected by local or regional supply and demand factors as well as other local market dynamics such as regional pipeline capacity. The prices the Company receives for its natural gas production 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. Supply Corporation and Empire experienced such a change at the Canada/United States border at the Niagara River, where gas prices increased relative to prices available at Leidy, Pennsylvania. This change in price differential caused shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. Supply Corporation and Empire saw transportation volumes decrease in 2009 and 2010 as a result of this situation, and in some cases, shippers decided not to renew transportation contracts. While much of the impact of lower volumes under existing contracts is 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. As contract renewals decrease, revenues and earnings in the Pipeline and Storage segment may decrease, as they did in 2010 and 2011. Supply Corporation and Empire responded to this changed gas price environment by developing projects designed to reverse the flow on their existing systems, as described elsewhere in this report, including Item 7, MD&A under the heading "Investing Cash Flow."

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 policy that the use of commodity derivatives contracts comply with various restrictions 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 includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as "swap dealers" and "major swap participants," (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC's enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate

commercial risk. Nevertheless, other rules that are being developed could have a

significant impact on the Company. For example, the CFTC has imposed numerous registration, swaps documentation, business conduct, reporting, and recordkeeping requirements on swap dealers and major swap participants, which frequently are counterparties to the Company's derivative hedging transactions. Similarly, the CFTC and various banking regulators have proposed rules that would require swap dealers and major swap participants subject to their jurisdiction to comply with certain obligations relating to capitalization and the collection of initial and variation margin from certain counterparties, although the recent proposals do not mandate the collection of margin from counterparties that qualify as non-financial end users, such as the Company. Regardless of the final capital and margin rules, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from the final and proposed rules through higher transaction costs and prices or other direct or indirect costs. In addition, while the Company expects to be exempt from the Dodd-Frank Act's requirement that swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company's ability to monetize or restructure existing derivative contracts; and increase the Company's exposure to less creditworthy counterparties, all of which could increase the Company's business costs.

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 12-month average 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 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 compare 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 12-month average prices 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.

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

Due to the burgeoning Marcellus Shale natural gas play in the northeast United States, together with the fiscal difficulties faced by state governments in New York and Pennsylvania, various state legislative and regulatory initiatives regarding the exploration and production business have been proposed. 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 or state 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. Implementing regulations, which will include new permit requirements, must be adopted to go into effect on July 1, 2015. These and any other new state or federal 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. 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 $5.7 billion at September 30, 2014. The Exploration and Production segment comprises 50.5% of this investment, and is primarily located in California and in the Appalachian region of the United States. Approximately 43.2% 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 comprises 5.1% 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%). 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 increased $2.6 billion, or 83.3%, since 2009. As part of its strategy to focus its exploration and production activities within the Appalachian region of the United States, specifically within the Marcellus Shale, the Company sold its off-shore oil and natural gas properties in the Gulf of Mexico in April 2011. The net property, plant and equipment associated with these properties was $55.4 million. The Company also sold on-shore oil and natural gas properties in its West Coast region in May 2011 with net property, plant and equipment of $8.1 million. In September 2010, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. The net property, plant and equipment of the landfill gas operations at the date of sale was $8.8 million.

The Exploration and Production segment had a net investment in property, plant and equipment of $2.9 billion at September 30, 2014.

The Pipeline and Storage segment had a net investment of $1.2 billion in property, plant and equipment at September 30, 2014. Transmission pipeline represents 38% of this segment’s total net investment and includes 2,350 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 17% of this segment’s total net investment and consist of 31 storage fields operating at a combined working gas level of 73.4 Bcf, four of which are jointly owned and operated with other interstate gas pipeline companies, and 432 miles of pipeline. Net investment in storage facilities includes $81.6 million of gas stored underground-noncurrent, representing the cost of the gas utilized to maintain pressure levels for normal operating purposes as well as gas maintained for system balancing and other purposes, including that needed for no-notice transportation service. The Pipeline and Storage segment has 33 compressor stations with 141,704 installed compressor horsepower that represent 20% of this segment’s total net investment in property, plant and equipment.

The Gathering segment had a net investment of $0.3 billion in property, plant and equipment at September 30, 2014. Gathering lines and related compressors comprise substantially all of this segment’s total net investment, including 61 miles of lines utilized to move Appalachian production (including Marcellus Shale) to various transmission pipeline receipt points. The Gathering segment has 2 compressor stations with 17,940 installed compressor horsepower.

The Utility segment had a net investment in property, plant and equipment of $1.3 billion at September 30, 2014. The net investment in its gas distribution network (including 14,782 miles of distribution pipeline) and its service connections to customers represent approximately 49% and 34%, respectively, of the Utility segment’s net investment in property, plant and equipment at September 30, 2014.

The Pipeline and Storage segments’ facilities provided the capacity to meet Supply Corporation’s 2014 peak day sendout for transportation service of 2,350 MMcf, which occurred on January 7, 2014. Withdrawals from storage of 802.5 MMcf provided approximately 34% 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 and purchase of, natural gas and oil reserves in California, the Appalachian region of the United States and Kansas. The Company has been increasing its emphasis in the Appalachian region, primarily in the Marcellus Shale, and sold its off-shore oil and natural gas properties in the Gulf of Mexico during 2011, as mentioned above. Further discussion of oil and gas producing activities is included in Item 8, Note M - Supplementary Information for Oil and Gas Producing Activities. Note M sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2014, 2013 and 2012 reserves shown in Note M 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 M 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 1,300 Bcf at September 30, 2013 to 1,683 Bcf at September 30, 2014. This increase is attributed to extensions and discoveries of 447 Bcf, acquisitions of 34 Bcf (both primarily Marcellus Shale) and positive revisions of previous estimates of 45 Bcf which were partially offset by production of 142 Bcf. Upward performance revisions of 45 Bcf were primarily performance revisions in the Marcellus Shale and included a 20 Bcf upward revision to Marcellus PUD reserves transferred to developed and a 13 Bcf upward revision to remaining Marcellus PUD reserves.

Seneca's proved developed and undeveloped oil reserves decreased from 41,598 Mbbl at September 30, 2013 to 38,477 Mbbl at September 30, 2014. Extensions and discoveries of 1,539 Mbbl were exceeded by production of 3,036 Mbbl primarily occurring in the West Coast region (3,005 Mbbl), and downward revisions of previous estimates of 1,694 Mbbl. Downward revisions were primarily a result of removing 1,501 Mbbl of proved undeveloped reserves at the Midway Sunset field in the Tulare reservoir as the Company has no near term plans to develop these reserves as it is employing its capital elsewhere. On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 1,549 Bcfe at September 30, 2013 to 1,914 Bcfe at September 30, 2014. Total revisions of previous estimates increased 35 Bcfe.

Seneca's proved developed and undeveloped natural gas reserves increased from 988 Bcf at September 30, 2012 to 1,300 Bcf at September 30, 2013. This increase was attributed to extensions and discoveries of 362 Bcf (355 Bcf in the Marcellus Shale) and positive revisions of previous estimates of 53 Bcf which were partially offset by production of 104 Bcf. Total gas revisions of 53 Bcf were composed of 8 Bcf in upward gas pricing revisions and 45 Bcf in upward performance revisions. Price related revisions were a result of higher trailing twelve month average gas prices (Dominion South Point average gas price increased $0.64 per MMBtu from $2.84 per MMBtu to $3.48 per MMBtu). Upward performance revisions of 45 Bcf were primarily in the Marcellus Shale and included an 11 Bcf upward revision to Marcellus PUD reserves transferred to developed and a 19 Bcf downward revision to remaining Marcellus PUD reserves.

Seneca's proved developed and undeveloped oil reserves decreased from 42,862 Mbbl at September 30, 2012 to 41,598 Mbbl at September 30, 2013. Extensions and discoveries of 2,443 Mbbl were exceeded by production of 2,831 Mbbl, primarily occurring in the West Coast region (2,803 Mbbl), and downward revisions of previous estimates of 876 Mbbl. On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 1,246 Bcfe at September 30, 2012 to 1,549 Bcfe at September 30, 2013.

At September 30, 2014, the Company's Exploration and Production segment had delivery commitments of 1,893 Bcfe (mostly natural gas as commitments for crude oil, gasoline, butane and propane was 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, the growth of proved gas reserves (which has averaged 30 percent over the past two years through the development of Seneca's large Appalachian acreage position) and (if necessary) from the purchase of natural gas and crude oil at index-related prices.

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					
	2014		2013		2012	
United States						
Appalachian Region						
Average Sales Price per Mcf of Gas	$3.55	(1)	$3.49	(1)	$2.71	(1)
Average Sales Price per Barrel of Oil	$96.34		$96.48		$93.94	
Average Sales Price per Mcf of Gas (after hedging)	$3.49		$4.00		$4.19	
Average Sales Price per Barrel of Oil (after hedging)	$96.34		$96.48		$93.94	
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$0.74	(1)	$0.67	(1)	$0.68	(1)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	382	(1)	276	(1)	172	(1)
West Coast Region						
Average Sales Price per Mcf of Gas	$6.75		$6.61		$6.27	
Average Sales Price per Barrel of Oil	$98.25		$103.14		$107.13	
Average Sales Price per Mcf of Gas (after hedging)	$6.65		$7.12		$8.54	
Average Sales Price per Barrel of Oil (after hedging)	$95.54		$98.23		$90.84	
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$2.96		$2.61		$1.98	
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	58		55		56	
Total Company						
Average Sales Price per Mcf of Gas	$3.62		$3.58		$2.89	
Average Sales Price per Barrel of Oil	$98.23		$103.07		$106.97	
Average Sales Price per Mcf of Gas (after hedging)	$3.56		$4.10		$4.42	
Average Sales Price per Barrel of Oil (after hedging)	$95.55		$98.21		$90.88	
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$1.03		$0.99		$1.00	
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	440		331		228	

The Marcellus Shale fields (which exceed 15% of total reserves at 9/30/2014, 9/30/2013 and 9/30/2012) contributed 361 MMcfe, 258 MMcfe and 152 MMcfe of daily production in 2014, 2013 and 2012, respectively.

(1) The average sales price (per Mcfe) was $3.53 ($3.47 after hedging) in 2014, $3.49 ($4.04 after hedging) in 2013 and $2.67 ($3.66 after hedging) in 2012. The average lifting costs (per Mcfe) were $0.72 in 2014, $0.64 in 2013 and $0.61 in 2012.

Productive Wells

	Appalachian Region		West Coast Region		Total Company	
At September 30, 2014	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	2,841	1	—	2,054	2,841	2,055
Productive Wells — Net	2,768	1	—	1,995	2,768	1,996

Developed and Undeveloped Acreage

At September 30, 2014	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
— Gross	559,044	24,730	583,774
— Net	549,296	21,457	570,753
Undeveloped Acreage			
— Gross	376,225	21,327	397,552
— Net	358,722	11,930	370,652
Total Developed and Undeveloped Acreage			
— Gross	935,269	46,057	981,326
— Net	908,018	33,387	941,405

As of September 30, 2014, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 20,941 acres in 2015 (17,336 net acres), 11,930 acres in 2016 (9,621 net acres), 12,756 acres in 2017 (9,104 net acres) and 43,561 acres thereafter (39,195 net acres). The remaining 308,364 gross acres (295,396 net acres) represent non-expiring oil and gas rights owned by the Company. Of the acreage that is currently scheduled to expire in 2015, 2016 and 2017, Seneca holds 56 Bcfe of proved undeveloped gas reserves, with 30 Bcfe subject to lease expirations in 2016 and 26 Bcfe subject to lease expirations in 2017. This total represents approximately 11% of Seneca's proved undeveloped reserves in the Marcellus Shale. Seneca intends to develop these reserves prior to the expiration of the leases as part of its management approved development plan.

Drilling Activity

	Productive			Dry		
For the Year Ended September 30	2014	2013	2012	2014	2013	2012
United States						
Appalachian Region						
Net Wells Completed						
— Exploratory	4.832	—	7.000	—	1.000	—
— Development	53.000	39.500	50.500	2.000	2.500	2.000
West Coast Region						
Net Wells Completed						
— Exploratory	1.533	0.625	—	—	—	—
— Development	84.720	74.996	56.990	1.000	—	—
Total Company						
Net Wells Completed						
— Exploratory	6.365	0.625	7.000	—	1.000	—
— Development	137.720	114.496	107.490	3.000	2.500	2.000

Present Activities

At September 30, 2014	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
— Gross	80.000	2.000	82.000
— Net	65.500	2.000	67.500

(1) Includes wells awaiting completion.

Item 3 Legal Proceedings

As previously reported, on November 14, 2012, the PaDEP sent a draft Consent Assessment of Civil Penalty to a subsidiary of Midstream Corporation. The draft Consent offered to settle various alleged violations of the Pennsylvania Clean Streams Law and the PaDEP's rules and regulations regarding erosion and sedimentation control if the Company would consent to a civil penalty. The alleged violations occurred during construction of the Company's Trout Run Gathering System following historic rainfall and flooding in the fall of 2011. In September 2014, the Company settled this matter with the PaDEP and paid a civil penalty of $250,000.

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.

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

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, Item 8 at Note E — Capitalization and Short-Term Borrowings, and at Note L — Market for Common Stock and Related Shareholder Matters (unaudited).

On July 1, 2014, the Company issued a total of 3,850 unregistered shares of Company common stock to the seven non-employee directors of the Company then serving on the Board of Directors of the Company, 550 shares to each such director. All of these unregistered shares were issued under the Company's 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors' services during the quarter ended September 30, 2014. 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, 2014	195	$72.30	—	6,971,019
Aug. 1-31, 2014	11,480	$75.67	—	6,971,019
Sept. 1-30, 2014	6,944	$76.30	—	6,971,019
Total	18,619	$75.87	—	6,971,019

(a) Represents shares of common stock of the Company tendered to the Company by holders of stock options, SARs, restricted stock units or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended September 30, 2014, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program.

(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, however, stopped repurchasing shares after September 17, 2008. Since that time, the Company has increased its emphasis on Marcellus Shale development and pipeline expansion. As such, the Company does not anticipate repurchasing any

shares 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 SIG Oil Exploration & Production Index for the period September 30, 2009 through September 30, 2014. The graph assumes that the value of the investment in the Company's common stock and in each index was $100 on September 30, 2009 and that all dividends were reinvested.

	2009	2010	2011	2012	2013	2014
National Fuel	$100	$116	$112	$127	$166	$173
S&P 500 Index	$100	$110	$111	$145	$173	$207
PHLX Utility Sector Index (UTY)	$100	$112	$125	$139	$145	$168
SIG Oil Exploration & Production Index (EPX)	$100	$108	$103	$119	$139	$138

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				
	2014	2013	2012	2011	2010
	(Thousands, except per share amounts and number of registered shareholders)				
Summary of Operations					
Operating Revenues	$2,113,081	$1,829,551	$1,626,853	$1,778,842	$1,760,503
Operating Expenses:					
Purchased Gas	605,838	460,432	415,589	628,732	658,432
Operation and Maintenance	463,078	442,090	401,397	400,519	394,569
Property, Franchise and Other Taxes	90,711	82,431	90,288	81,902	75,852
Depreciation, Depletion and Amortization	383,781	326,760	271,530	226,527	191,199
	1,543,408	1,311,713	1,178,804	1,337,680	1,320,052
Operating Income	569,673	517,838	448,049	441,162	440,451
Other Income (Expense):					
Gain on Sale of Unconsolidated Subsidiaries	—	—	—	50,879	—
Other Income	9,461	4,697	5,133	5,947	6,126
Interest Income	4,170	4,335	3,689	2,916	3,729
Interest Expense on Long-Term Debt	(90,194)	(90,273)	(82,002)	(73,567)	(87,190)
Other Interest Expense	(4,083)	(3,838)	(4,238)	(4,554)	(6,756)
Income from Continuing Operations Before Income Taxes	489,027	432,759	370,631	422,783	356,360
Income Tax Expense	189,614	172,758	150,554	164,381	137,227
Income from Continuing Operations	299,413	260,001	220,077	258,402	219,133
Discontinued Operations:					
Income from Operations, Net of Tax	—	—	—	—	470
Gain on Disposal, Net of Tax	—	—	—	—	6,310
Income from Discontinued Operations, Net of Tax	—	—	—	—	6,780
Net Income Available for Common Stock	$299,413	$260,001	$220,077	$258,402	$225,913
Per Common Share Data					
Basic Earnings from Continuing Operations per Common Share	$3.57	$3.11	$2.65	$3.13	$2.70
Diluted Earnings from Continuing Operations per Common Share	$3.52	$3.08	$2.63	$3.09	$2.65
Basic Earnings per Common Share(1)	$3.57	$3.11	$2.65	$3.13	$2.78
Diluted Earnings per Common Share(1)	$3.52	$3.08	$2.63	$3.09	$2.73
Dividends Declared	$1.52	$1.48	$1.44	$1.40	$1.36
Dividends Paid	$1.51	$1.47	$1.43	$1.39	$1.35
Dividend Rate at Year-End	$1.54	$1.50	$1.46	$1.42	$1.38
At September 30:					
Number of Registered Shareholders	12,654	13,215	13,800	14,355	15,549

	Year Ended September 30				
	2014	2013	2012	2011	2010
	(Thousands, except per share amounts and number of registered shareholders)				
Net Property, Plant and Equipment					
Exploration and Production	$2,897,744	$2,600,448	$2,273,030	$1,753,194	$1,338,956
Pipeline and Storage	1,187,924	1,074,079	1,069,070	954,554	858,231
Gathering	292,793	161,111	110,269	31,962	15,585
Utility	1,297,179	1,246,943	1,217,431	1,189,030	1,165,240
Energy Marketing	2,070	2,002	1,530	850	436
All Other	61,236	62,554	63,245	65,266	65,518
Corporate	4,145	4,589	5,228	5,668	6,263
Total Net Plant	$5,743,091	$5,151,726	$4,739,803	$4,000,524	$3,450,229
Total Assets	$6,739,597	$6,218,347	$5,935,142	$5,221,084	$5,047,054
Capitalization					
Comprehensive Shareholders' Equity	$2,410,683	$2,194,729	$1,960,095	$1,891,885	$1,745,971
Long-Term Debt, Net of Current Portion	1,649,000	1,649,000	1,149,000	899,000	1,049,000
Total Capitalization	$4,059,683	$3,843,729	$3,109,095	$2,790,885	$2,794,971

(1) Includes discontinued operations.

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 model centered in western New York and Pennsylvania, an area critical to the production and transportation of natural gas from the Marcellus Shale basin. 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 Marcellus Shale 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. Refer to Item 1, Business, for a more detailed description of each of the segments. 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) 2014 and projected 2015 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, 2014 compared to the year ended September 30, 2013, the Company experienced an increase in earnings of $39.4 million. The earnings increase is primarily due to higher earnings in the Pipeline and Storage segment, Gathering segment, Exploration and Production segment and Energy Marketing segment, slightly offset by lower earnings in the Utility segment and a higher loss in the Corporate category. For further discussion of the Company's earnings, refer to the Results of Operations section below.

The Company's natural gas reserve base continues to grow due to its development of reserves in the 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. The Company controls the natural gas interests associated with approximately 780,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations. Natural gas proved developed and undeveloped reserves in the Appalachian region increased from 1,239 Bcf at September 30, 2013 to 1,624 Bcf at September 30, 2014. The Company has spent significant amounts of capital in this region related to the development of such reserves. For the year ended September 30, 2014, the Company's Exploration and Production segment had capital expenditures of $519.9 million in the Appalachian region, of which $502.9 million was spent towards the development of the Marcellus Shale. The amount spent towards the development of the Marcellus Shale represented approximately 52% of the Company's capital expenditures for the year ended September 30, 2014. The Company's fiscal 2015 estimated capital expenditures in the Exploration and Production segment's Appalachian region are expected to be approximately $585 million. Forecasted production in the Exploration and Production segment's Appalachian region for fiscal 2015 is expected to be in the range of 159 to 197 Bcfe, up from actual Appalachia production of 139 Bcfe in fiscal 2014.

To facilitate the flow of natural gas from the Marcellus Shale, the Company continues to expand its gathering and pipeline infrastructure in the Gathering segment and the Pipeline and Storage segment. For the year ended September 30, 2014, the Gathering segment had capital expenditures of $137.8 million and its estimated capital expenditures in fiscal 2015 are expected to be approximately $175 million. The Pipeline and Storage segment's capital expenditures for the year ended September 30, 2014 were $139.8 million and its estimated capital expenditures in fiscal 2015 are expected to be approximately $250 million. The amount spent towards the development of gathering and pipeline infrastructure in fiscal 2014 represented approximately 29% of the Company's capital expenditures.

From a capital resources perspective, the Company has largely been able to meet its capital expenditure needs by using cash from operations as well as both short and long-term debt. It is expected that the Company will issue short-term and long-term debt as necessary during fiscal 2015 to help meet its capital expenditure needs.

The well completion technology referred to as hydraulic fracturing used in conjunction with horizontal drilling continues to be debated. In Pennsylvania, where the Company is focusing its Marcellus Shale development efforts, the permitting and regulatory processes seem to strike a balance between the environmental concerns associated with hydraulic fracturing and the benefits of increased natural gas production. The potential for increased state or federal regulation of hydraulic fracturing could impact future costs of drilling in the Marcellus Shale and lead to operational delays or restrictions. There is also the risk that drilling could be prohibited on certain acreage that is prospective for the Marcellus Shale. Please refer to the Risk Factors section above for further discussion.

CRITICAL ACCOUNTING ESTIMATES

The Company has prepared its consolidated financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates. In the event estimates or assumptions prove to be different from actual results, adjustments are made in subsequent periods to reflect more current information. The following is a summary of the Company's most critical accounting estimates, which are defined as those estimates whereby judgments or

uncertainties could affect the application of accounting policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the Company's significant accounting policies, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

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

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

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions to or subtractions from proved reserves and significant fluctuations in oil and gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment charge must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. At September 30, 2014, the ceiling exceeded the book value of the Company's oil and gas properties by approximately $148.4 million. The 12-month average of the first day of the month price for crude oil for each month during 2014, based on posted Midway Sunset prices, was $97.30 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2014, based on the quoted Henry Hub spot price for natural gas, was $4.24 per MMBtu. (Note — Because actual pricing of the Company's various producing properties varies depending on their location and hedging, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for 2014.) If natural gas average prices used in the ceiling test calculation at September 30, 2014 had been $1 per MMBtu lower, the book value of the Company's oil and gas properties would have exceeded the

ceiling by approximately $254.2 million, which would have resulted in an impairment charge. If crude oil average prices used in the ceiling test calculation at September 30, 2014 had been $5 per Bbl lower, the ceiling

would have exceeded the book value of the Company's oil and gas properties by approximately $106.8 million which would not have resulted in an impairment charge. If both natural gas and crude oil average prices used in the ceiling test calculation at September 30, 2014 were lower by $1 per MMBtu and $5 per Bbl, respectively, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $295.9 million, which would have resulted in an impairment charge. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation.

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 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. 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 utilizes the Mercer Yield Curve Above Mean Model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments. In determining the spot rates, the model will exclude coupon interest rates that are in the lower 50th percentile 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 was changed from 4.75% in 2013 to 4.25% in 2014. The change in the discount rate from 2013 to 2014 increased the Retirement Plan projected benefit obligation by $53.7 million and the accumulated post-retirement benefit obligation by $26.4 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 2014, the actual return on plan assets exceeded the expected return, which improved the funded status of the Retirement Plan ($33.3 million) as well as the VEBA trusts and 401(h) accounts ($7.5 million). The actual versus expected benefit payments for 2014 caused a decrease of $3.7 million to the accumulated post-retirement benefit obligation. 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 6 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.

RESULTS OF OPERATIONS

EARNINGS

2014 Compared with 2013

The Company's earnings were $299.4 million in 2014 compared with earnings of $260.0 million in 2013. The increase in earnings of $39.4 million is primarily a result of higher earnings in the Exploration and Production segment, Pipeline and Storage segment, Gathering segment and Energy Marketing segment. Lower earnings in the Utility segment and a higher loss in the Corporate category slightly 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 events in 2014 and 2013:

2014 Event

- A $3.6 million death benefit gain on life insurance proceeds recorded in the Corporate category.

2013 Event

- A $4.9 million refund provision recorded in the Utility segment related to various issues raised in Distribution Corporation's rate proceeding in New York.

2013 Compared with 2012

The Company's earnings were $260.0 million in 2013 compared with earnings of $220.1 million in 2012. The increase in earnings of $39.9 million is the result of higher earnings in all segments. Higher earnings in the All Other category and a lower loss in the Corporate category also contributed to the increase in earnings. Earnings were impacted by the 2013 event discussed above and the following events in 2012:

2012 Events

- The elimination of Supply Corporation's other post-retirement regulatory liability of $12.8 million recorded in the Pipeline and Storage segment, as specified by Supply Corporation's rate case settlement; and
- A natural gas impact fee imposed by the Commonwealth of Pennsylvania in 2012 on the drilling of wells in the Marcellus Shale by the Exploration and Production segment. This fee included $4.0 million related to wells drilled prior to 2012.

Earnings (Loss) by Segment

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Exploration and Production	$121,569	$115,391	$96,498
Pipeline and Storage	77,559	63,245	60,527
Gathering	32,709	13,321	6,855
Utility	64,059	65,686	58,590
Energy Marketing	6,631	4,589	4,169
Total Reported Segments	302,527	262,232	226,639
All Other	1,160	894	13
Corporate	(4,274)	(3,125)	(6,575)
Total Consolidated	$299,413	$260,001	$220,077

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Gas (after Hedging)	$506,491	$424,735	$292,311
Oil (after Hedging)	290,030	278,005	260,844
Gas Processing Plant	4,831	4,502	4,813
Other	2,744	(4,305)	212
Operating Revenues	$804,096	$702,937	$558,180

Production

	Year Ended September 30		
	2014	2013	2012
Gas Production (MMcf)			
Appalachia	139,097	100,633	62,663
West Coast	3,210	3,060	3,468
Total Production	142,307	103,693	66,131
Oil Production (Mbbl)			
Appalachia	31	28	36
West Coast	3,005	2,803	2,834
Total Production	3,036	2,831	2,870

Average Prices

	Year Ended September 30		
	2014	2013	2012
Average Gas Price/Mcf			
Appalachia	$3.55	$3.49	$2.71
West Coast	$6.75	$6.61	$6.27
Weighted Average	$3.62	$3.58	$2.89
Weighted Average After Hedging(1)	$3.56	$4.10	$4.42
Average Oil Price/Barrel (bbl)			
Appalachia	$96.34	$96.48	$93.94
West Coast	$98.25	$103.14	$107.13
Weighted Average	$98.23	$103.07	$106.97
Weighted Average After Hedging(1)	$95.55	$98.21	$90.88

(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.

2014 Compared with 2013

Operating revenues for the Exploration and Production segment increased $101.2 million in 2014 as compared with 2013. Gas production revenue after hedging increased $81.8 million primarily due to production increases in the Appalachian division. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, primarily in Lycoming County, Pennsylvania. This was partially offset by a $0.54 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging increased $12.0 million due to an increase in production, which was partially offset by a $2.66 per Bbl decrease in the weighted average price of oil after hedging. The increase in crude oil production was largely due to increased development in the East Coalinga, Sespe and South Midway Sunset fields in California. The increase in other revenue ($7.0 million) was largely due to a $3.6 million positive variance in mark-to-market charges related to hedging ineffectiveness, settlement proceeds received in 2014 related to former insurance policies ($1.9 million) and the non-recurrence of a royalty adjustment (including interest) recorded in 2013 ($1.8 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.

2013 Compared with 2012

Operating revenues for the Exploration and Production segment increased $144.8 million in 2013 as compared with 2012. Gas production revenue after hedging increased $132.4 million primarily due to production increases in the Appalachian division. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, primarily in Lycoming County, Pennsylvania. This was partially offset by a $0.32 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging increased $17.2 million due to an increase in the weighted average price of oil after hedging ($7.33 per Bbl). Oil production was slightly lower year over year, largely the result of a continued constraint in a third-party pipeline used to transport natural gas production within the Sespe Field. The constraint on natural gas transportation capacity impacts oil production in that natural gas is a byproduct of the Exploration and Production segment's oil production at the Sespe Field. The decrease in other revenue ($4.5 million) was largely due to a $3.7 million mark-to-market charge related to hedging ineffectiveness.

Earnings

2014 Compared with 2013

The Exploration and Production segment's earnings for 2014 were $121.6 million, compared with earnings of $115.4 million for 2013, an increase of $6.2 million. The main drivers of the increase were higher natural gas production ($102.8 million), higher crude oil production ($13.1 million) and lower income taxes ($11.2 million). In addition, the earnings impact of the increase in other revenues ($4.6 million) also contributed to the increase in earnings, as discussed above. The decrease in income taxes was largely due to an increase in firm transportation of natural gas to Canadian delivery points, which decreased the effective tax rate used in the calculation of deferred tax expense. These earnings increases were partially offset by the earnings impact of higher depletion expense ($34.3 million), lower natural gas prices after hedging ($49.7 million), higher production costs ($30.1 million), higher general, administrative and other expense ($2.7 million), higher interest expense ($1.6 million), higher property and other taxes ($2.3 million) and lower crude oil prices after hedging ($5.3 million). The increase in depletion expense is primarily due to increased Appalachian natural gas production (primarily in the Marcellus Shale formation). The increase in production costs was largely attributable to higher transportation costs. The increase in general, administrative and other expense was largely due to an increase in personnel costs and the accrual of plugging and abandonment costs associated with offshore properties no longer owned by the Exploration and Production segment. The increase in interest expense was attributable to an increase in the weighted average amount of debt due to the Exploration and Production segment's share of the Company's $500 million long-term debt issuance in February 2013.

2013 Compared with 2012

The Exploration and Production segment's earnings for 2013 were $115.4 million, compared with earnings of $96.5 million for 2012, an increase of $18.9 million. The main drivers of the increase were higher natural gas production ($107.9 million) and higher crude oil prices after hedging ($13.5 million). In addition, there was a decrease in property and other taxes ($4.2 million) which largely reflects the non-recurrence of a $4.0 million natural gas impact fee accrual recorded during the quarter ended March 31, 2012 related to Marcellus Shale wells drilled prior to fiscal 2012. These earnings increases were partially offset by the earnings impact of higher depletion expense ($36.3 million), lower natural gas prices after hedging ($21.8 million), higher production costs ($23.3 million), higher general, administrative and other expense ($9.0 million), higher interest expense ($6.8 million), higher income taxes ($4.0 million), a derivative mark-to-market charge ($2.7 million) and lower crude oil production ($2.3 million). The increase in depletion expense is primarily due to increased Appalachian natural gas production (primarily in the Marcellus Shale formation). The increase in production costs was largely attributable to higher transportation costs resulting from higher production. In addition, compression and water disposal costs in the Appalachian region coupled with higher well repair, maintenance and labor costs in the West Coast region led to further increases in production costs. The increase in general, administrative and other expense was largely due to an increase in personnel costs. The increase in interest expense was attributable to an increase in the weighted average amount of debt due to the Exploration and Production segment's share of both the Company's $500 million long-term debt issuance in February 2013 and the Company's $500 million long-term debt issuance in December 2011. The increase in income tax expense is largely attributable to higher state income taxes.

PIPELINE AND STORAGE
Revenues
Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Firm Transportation	$207,892	$190,470	$164,652
Interruptible Transportation	2,666	2,152	1,431
	210,558	192,622	166,083
Firm Storage Service	69,878	70,555	67,929
Interruptible Storage Service	13	5	7
	69,891	70,560	67,936
Other	3,959	4,426	25,256
	$284,408	$267,608	$259,275

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2014	2013	2012
Firm Transportation	731,271	575,805	369,477
Interruptible Transportation	4,724	3,997	1,662
	735,995	579,802	371,139

2014 Compared with 2013
Operating revenues for the Pipeline and Storage segment increased $16.8 million in 2014 as compared with 2013. The increase was primarily due to an increase in transportation revenues of $17.9 million slightly offset by a decrease in storage revenues of $0.7 million. The increase in transportation revenues was largely due to demand and commodity charges on new contracts for transportation service on Supply Corporation’s Northern Access expansion project, which was placed fully in service in January 2013, Supply Corporation’s Line N 2012 Expansion Project, which was placed fully in service in November 2012 and Supply Corporation's Line N 2013 Project, which was placed in service in November 2013. In addition, the increase in transportation revenues was due to additional demand charges associated with the full-ramp up of a transportation contract for an anchor shipper on Empire's Tioga County Extension Project as well as additional commodity charges associated with that contract due to higher throughput flowing through a secondary receipt point. These projects provide pipeline capacity for Marcellus Shale production. Also contributing to the increase in transportation revenues was additional non-expansion revenue as a result of new short-term contracts for both Empire and Supply Corporation and new contracts for transportation service from an Open Season Supply Corporation held near the end of fiscal 2013. Partially offsetting these increases was a decrease in storage revenues due to a decline in demand charges as a result of contract restructuring.
Transportation volume increased by 156.2 Bcf in 2014 as compared with 2013. The large increase in transportation volume primarily reflects the impact of the above mentioned expansion projects being placed in service and new contracts for transportation service. The increase was enhanced by weather that was significantly colder than the prior year and colder than normal.

2013 Compared with 2012

Operating revenues for the Pipeline and Storage segment increased $8.3 million in 2013 as compared with 2012. The increase was primarily due to an increase in transportation revenues of $26.5 million and an increase in storage revenues of $2.6 million. The increase in transportation revenues was largely due to demand charges on new contracts for transportation service on Supply Corporation's Line N 2012 Expansion Project, which was placed fully in service in November 2012, and Supply Corporation's Northern Access expansion project, which was placed fully in service in January 2013. These projects provide pipeline capacity for Marcellus Shale production. Additionally, effective May 2012, both transportation and storage revenues increased due to an overall net increase in tariff rates as a result of the implementation of Supply Corporation's rate case settlement which was approved by FERC on August 6, 2012. Partially offsetting these increases was a decrease in other operating revenues. Other operating revenues in fiscal 2012 included the impact of Supply Corporation's elimination of a $21.7 million regulatory liability associated with post-retirement benefits. The elimination of the regulatory liability was specified in Supply Corporation's rate case settlement.

Transportation volume increased by 208.7 Bcf in 2013 as compared with 2012. The large increase in transportation volume primarily reflects the impact of the above mentioned expansion projects being placed in service.

Earnings

2014 Compared with 2013

The Pipeline and Storage segment's earnings in 2014 were $77.6 million, an increase of $14.4 million when compared with earnings of $63.2 million in 2013. The increase in earnings is primarily due to the earnings impact of higher transportation revenues of $11.7 million, as discussed above, combined with lower operating expenses ($6.3 million). The decrease in operating expenses primarily reflects lower pension and other post-retirement benefit costs and a decrease in the reserve for preliminary project costs offset partially by higher pipeline integrity program expenses. These earnings increases were partially offset by an increase in depreciation expense ($1.0 million), higher property taxes ($0.9 million), a decrease in the allowance for funds used during construction (equity component) of $0.4 million, higher income taxes ($0.5 million) and the earnings impact of lower storage revenue ($0.4 million), as discussed above. The increase in depreciation expense is attributable to incremental depreciation expense related to the projects that were placed in service within the last year. The increase in property taxes is primarily due to the addition of new plant. The decrease in the allowance for funds used during construction is mainly due to Supply Corporation's Line N 2012 Expansion Project and Supply Corporation's Northern Access expansion project, which remained under construction in the first quarter of the prior year and have since been placed in service. The increase in income taxes is a result of higher state taxes combined with a reduction in benefits associated with the tax sharing agreement with affiliated companies.

2013 Compared with 2012

The Pipeline and Storage segment's earnings in 2013 were $63.2 million, an increase of $2.7 million when compared with earnings of $60.5 million in 2012. The increase in earnings is primarily due to the earnings impact of higher transportation and storage revenues of $19.0 million, as discussed above, combined with a decrease in depreciation expense ($2.0 million). The decrease in depreciation expense primarily reflects a decrease in depreciation rates as specified in Supply Corporation's rate case settlement offset partly by incremental depreciation expense related to the projects that were placed in service within the last year. Partially offsetting these increases was the non-recurrence of the fiscal 2012 elimination of Supply Corporation's post-retirement regulatory liability ($12.8 million), as discussed above. The earnings increases were also partially offset by higher operating expenses ($2.6 million), a decrease in the allowance for funds used during construction (equity component) of $1.4 million, higher property taxes ($0.5 million), higher interest expense ($0.4 million) and higher income taxes ($1.0 million). The increase in operating expenses can be attributed primarily to higher pension expense and an increase in compressor station costs, offset partly by lower post-retirement benefit costs. The decrease in the allowance for funds used during construction is mainly due to Supply Corporation's Line N 2012 Expansion Project and Supply Corporation's Northern Access expansion project, which were under construction in the prior year and were placed

in service during fiscal 2013, and Empire's Tioga County Expansion Project, which remained under construction during a portion of the first quarter of fiscal 2012 before being placed in service in November 2011. The increase in property taxes was primarily a result of a higher tax base due to capital additions. Increased intercompany borrowings contributed to the increase in interest expense. The increase in income taxes is a result of a favorable federal return to provision adjustment in 2012 that did not recur in the current year combined with a reduced benefit associated with the allowance for funds used during construction.

GATHERING

Revenues

Gathering Operating Revenues

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Gathering	$69,937	$33,815	$16,771
Processing and Other Revenues	673	966	704
	$70,610	$34,781	$17,475

Gathering Volume — (MMcf)

	Year Ended September 30		
	2014	2013	2012
Gathered Volume	138,726	93,449	48,562

2014 Compared with 2013

Operating revenues for the Gathering segment increased $35.8 million in 2014 as compared with 2013. This increase was largely due to an increase in gathering revenues driven by a 45.3 Bcf increase in gathered volume combined with higher gathering rates. The overall increase in gathered volume was largely due to a 40.7 Bcf increase in gathered volume on Midstream Corporation's Trout Run Gathering System (Trout Run) and a 4.5 Bcf increase in gathered volume on Midstream Corporation's Clermont Gathering System (Clermont). Most of the increase in gathered volume is attributable to an increase in Seneca's Marcellus Shale production, primarily in Lycoming County, Pennsylvania.

2013 Compared with 2012

Operating revenues for the Gathering segment increased $17.3 million in 2013 as compared with 2012 largely due to an increase in gathering revenues driven by a 44.9 Bcf increase in gathered volume. This increase was primarily due to Trout Run which was placed in service in May 2012 and the expansion of Midstream Corporation's Covington Gathering System (Covington). Trout Run and Covington provide gathering services for Seneca's production.

Earnings

2014 Compared with 2013

The Gathering segment's earnings in 2014 were $32.7 million, an increase of $19.4 million when compared with earnings of $13.3 million in 2013. The increase in earnings is mainly due to the earnings impact of higher gathering revenues ($23.5 million) and lower interest expense ($0.4 million). These earnings increases were partially offset by higher income tax expense ($1.9 million), higher depreciation expense ($1.4 million) and higher operating expenses ($1.0 million). The significant growth of Trout Run is primarily responsible for the revenue, depreciation expense and operating expense variations. The increase in income tax expense was largely due to higher state taxes. The decrease in interest expense is largely due to an increase in capitalized interest, which more

than offset the impact of an increase in the weighted average amount of debt due to the Gathering segment's share of the $500 million long-term debt issuance in February 2013.

2013 Compared with 2012

The Gathering segment's earnings in 2013 were $13.3 million, an increase of $6.4 million when compared with earnings of $6.9 million in 2012. The increase in earnings is due to higher gathering and processing revenues ($11.2 million). This was partially offset by higher operating expenses ($1.5 million), higher depreciation expense ($1.5 million), higher income tax expense ($1.3 million), and higher interest expense ($0.5 million). The completion of Trout Run and the expansion of Covington are primarily responsible for the revenue, operating expense and depreciation expense variations. The increase in income tax expense was largely due to higher state taxes and a true-up adjustment related to the filed federal return. The increase in interest expense was due to an increase in the weighted average amount of debt due to the Gathering segment's share of both the Company's $500 million long-term debt issuance in February 2013 and the Company's $500 million long-term debt issuance in December 2011.

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Retail Revenues:			
Residential	$590,080	$513,654	$493,354
Commercial	78,036	66,602	61,314
Industrial	3,692	6,096	5,359
	671,808	586,352	560,027
Off-System Sales	19,712	25,020	27,010
Transportation	150,158	135,273	122,316
Other	7,940	(306)	9,769
	$849,618	$746,339	$719,122

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2014	2013	2012
Retail Sales:			
Residential	60,101	52,753	47,036
Commercial	8,834	7,486	6,682
Industrial	393	947	837
	69,328	61,186	54,555
Off-System Sales	4,564	6,717	9,544
Transportation	80,949	69,149	61,027
	154,841	137,052	125,126

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Prior Year
2014(1)	Buffalo	6,617	7,087	7.1 %	15.4 %
	Erie	6,147	6,742	9.7 %	14.5 %
2013(2)	Buffalo	6,617	6,139	(7.2)%	15.9 %
	Erie	6,147	5,888	(4.2)%	17.8 %
2012(3)	Buffalo	6,729	5,296	(21.3)%	(21.6)%
	Erie	6,277	4,999	(20.4)%	(21.4)%

(1) Percents compare actual 2014 degree days to normal degree days and actual 2014 degree days to actual 2013 degree days.

(2) Percents compare actual 2013 degree days to normal degree days and actual 2013 degree days to actual 2012 degree days. Normal degree days for 2013 reflect a revision from the National Oceanic and Atmospheric Administration.

(3) Percents compare actual 2012 degree days to normal degree days and actual 2012 degree days to actual 2011 degree days. Normal degree days for 2012 reflect the fact that 2012 was a leap year.

2014 Compared with 2013

Operating revenues for the Utility segment increased $103.3 million in 2014 compared with 2013. This increase largely resulted from an $85.5 million increase in retail gas sales revenues and a $14.9 million increase in transportation revenue. In addition, there was an $8.2 million increase in other operating revenues. These were partially offset by a $5.3 million decrease in off-system sales (due to lower volume). The decrease in off-system sales volume was due to the Utility segment’s greater utilization of pipeline capacity in order to reliably meet the increased demand for its retail gas brought on by colder weather experienced during the winter of the current year. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal.

The $85.5 million increase in retail gas sales revenues was largely a function of higher volume (8.1 Bcf) due to colder weather. The $14.9 million increase in transportation revenues was primarily due to an 11.8 Bcf increase in transportation throughput, largely the result of colder weather compared to the prior period and the migration of customers from retail sales to transportation services. The $8.2 million increase in other operating revenues was largely due to the non-recurrence of a $7.5 million refund provision recorded during fiscal 2013 related to various issues raised in a New York rate proceeding. During 2014, the Utility segment recorded an earnings share adjustment pursuant to the settlement resulting from that rate proceeding ($2.5 million reduction to revenues). However, this was largely offset by a 2014 true-up of regulatory asset balances associated with insurance proceeds on site remediation claims ($2.3 million).

2013 Compared with 2012

Operating revenues for the Utility segment increased $27.2 million in 2013 compared with 2012. This increase largely resulted from a $26.3 million increase in retail gas sales revenues and a $13.0 million increase in transportation revenue. These were partially offset by a $10.1 million decrease in other operating revenues and a $2.0 million decrease in off-system sales (due to lower volume). Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal.

The $26.3 million increase in retail gas sales revenues was largely a function of higher volume (6.6 Bcf) due to colder weather. The $13.0 million increase in transportation revenues was primarily due to an 8.1 Bcf increase in transportation throughput, largely the result of colder weather compared to the prior period and the migration of customers from retail sales to transportation services. The $10.1 million decrease in other operating revenues was

largely due to a $7.5 million refund provision recorded during fiscal 2013 related to various issues raised in

a New York rate proceeding combined with a downward adjustment in the carrying value of certain regulatory assets during the fourth quarter of fiscal 2013. In addition, a decline in capacity release revenues led to a decline in other revenues. As a result of the unusually warm winter during fiscal 2012, the demand for capacity release volume decreased as contracts for Distribution Corporation's fiscal 2013 capacity were being executed, which led to a decrease in the capacity release rates and revenues.

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 $446.9 million, $362.3 million and $340.3 million of Purchased Gas expense during 2014, 2013 and 2012, respectively. Under its purchased gas adjustment clauses in New York and Pennsylvania, Distribution Corporation is not allowed to profit from fluctuations in gas costs. Purchased gas expense recorded on the consolidated income statement matches the revenues collected from customers, a component of Operating Revenues on the consolidated income statement. Under mechanisms approved by the NYPSC in New York and the PaPUC in Pennsylvania, any difference between actual purchased gas costs and what has been collected from the customer is deferred on the consolidated balance sheet as either an asset, Unrecovered Purchased Gas Costs, or a liability, Amounts Payable to Customers. These deferrals are subsequently collected from the customer or passed back to the customer, subject to review by the NYPSC and the PaPUC. Absent disallowance of full recovery of Distribution Corporation's purchased gas costs, such costs do not impact the profitability of the Company. Purchased gas costs impact cash flow from operations due to the timing of recovery of such costs versus the actual purchased gas costs incurred during a particular period. Distribution Corporation's purchased gas adjustment clauses seek to mitigate this impact by adjusting revenues on either a quarterly or monthly basis.

Currently, Distribution Corporation has contracted for long-term firm transportation capacity with Supply Corporation, Empire and seven other upstream pipeline companies, for long-term gas supplies with a combination of producers and marketers, and for storage service with Supply Corporation and two nonaffiliated companies. In addition, Distribution Corporation satisfies a portion of its gas requirements through spot market purchases. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Earnings

2014 Compared with 2013

The Utility segment's earnings in 2014 were $64.1 million, a decrease of $1.6 million when compared with earnings of $65.7 million in 2013. The decrease in earnings is largely attributable to an increase in operating expenses ($9.1 million), an increase in income tax expense ($2.4 million), the impact of an earnings sharing adjustment ($1.6 million) and an increase in property and other taxes ($0.8 million). The increase in operating expenses is largely attributable to increased costs associated with defined benefit and defined contribution retirement plans as a result of a recent settlement with the NYPSC and an increase in bad debt expense. The increase in income tax expense is largely due to higher state income taxes and the reversal of tax expense that occurred in 2013 (as a result of a favorable tax settlement), which did not recur in 2014. The increase in property and other taxes is largely due to increases in FICA, school, town and county taxes. These earnings decreases were partially offset by the impact of colder weather in Pennsylvania ($5.8 million), the positive earnings impact of the non-recurrence of the refund provision recorded in fiscal 2013 ($4.9 million), a true-up of regulatory asset balances associated with a NYPSC settlement concerning insurance proceeds on site remediation claims ($1.5 million) and the earnings impact of lower interest expense ($0.9 million). The decrease in interest expense is due to a decrease in the weighted average amount of debt outstanding due to the Utility segment's share of the Company's $250 million of notes that matured in March 2013.

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 2014, the WNC reduced earnings by approximately $3.0 million as the weather was colder than normal. In 2013, the WNC preserved earnings of approximately $2.1 million as the weather was warmer than normal.

2013 Compared with 2012

The Utility segment's earnings in 2013 were $65.7 million, an increase of $7.1 million when compared with earnings of $58.6 million in 2012. The increase in earnings is largely attributable to colder weather ($7.0 million), the positive earnings impact of lower interest expense ($2.7 million), lower income tax expense ($1.2 million), and higher usage ($0.7 million). These increases were partially offset by a $4.9 million refund provision discussed above. Usage refers to average gas consumption per account after factoring out any impact that weather may have had on consumption. The decrease in interest expense is due to a decrease in the weighted average amount of debt outstanding due to the Utility segment's share of the Company's $250 million of notes that matured in March 2013. The decrease in income tax expense is a result of a favorable tax settlement.

For 2012, the WNC preserved earnings of approximately $5.9 million as the weather was warmer than normal.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Natural Gas (after Hedging)	$273,099	$213,324	$187,969
Other	53	50	35
	$273,152	$213,374	$188,004

Energy Marketing Volume

	Year Ended September 30		
	2014	2013	2012
Natural Gas — (MMcf)	52,694	46,875	45,756

2014 Compared with 2013

Operating revenues for the Energy Marketing segment increased $59.8 million in 2014 as compared with 2013. The increase reflects an increase in gas sales revenue due to a higher average price of natural gas period over period and an increase in volume sold to retail customers as a result of colder weather. Effective with the first quarter of 2014, the Energy Marketing segment began recording unbilled revenue. Operating revenues for the year ended September 30, 2014 include an $8.5 million accrual for unbilled revenue while operating revenues for the year ended September 30, 2013 do not include such an accrual. The volume associated with unbilled revenue at September 30, 2014 was 2,122 MMcf.

2013 Compared with 2012

Operating revenues for the Energy Marketing segment increased $25.4 million in 2013 as compared with 2012. The increase reflects an increase in gas sales revenue due to a higher average price of natural gas as well as an increase in volume sold due to colder weather.

Earnings

2014 Compared with 2013

The Energy Marketing segment's earnings in 2014 were $6.6 million, an increase of $2.0 million when compared with earnings of $4.6 million in 2013. This increase in earnings was largely attributable to higher margin of $2.2 million, which primarily reflects the positive impact on margin from the increase in volume sold to retail customers due to colder weather during 2014 combined with improved average margin per Mcf. To a lesser extent, margin was also positively impacted by the recording of unbilled revenues and related gas costs at September 30, 2014, as discussed below. These earnings increases were partially offset by a decline in the benefit the Energy Marketing segment realized from its contracts for storage capacity.

Energy Marketing segment revenues and related purchased gas costs in prior year periods were recorded when billed, resulting in a one month lag. Effective with the first quarter of 2014, the Energy Marketing segment began recording unbilled revenue and related gas costs. The impact of this change for the year ended September 30, 2014 was to increase operating revenues and margin by $8.5 million and $0.6 million, respectively. Management has determined that the impact of not recording unbilled revenue and related gas costs was immaterial in all prior periods.

2013 Compared with 2012

The Energy Marketing segment's earnings in 2013 were $4.6 million, an increase of $0.4 million when compared with earnings of $4.2 million in 2012. This increase in earnings was largely attributable to higher margin of $0.5 million, primarily driven by an increase in the benefit the Energy Marketing segment derived from its contracts for storage capacity.

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. In September 2012, the Company recorded an impairment charge ($1.1 million) to write-off the remaining value of Horizon Power's investment in ESNE, a dormant 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. In March 2014, ESNE sold its turbine assets associated with this plant.

Earnings

2014 Compared with 2013

All Other and Corporate operations recorded a loss of $3.1 million in 2014, which was $0.9 million higher than the loss of $2.2 million in 2013. The increase in loss was primarily due to higher income tax expense of $4.7 million (primarily due to consolidated tax sharing and an adjustment for an intercompany deferred tax reallocation recorded in 2013 that did not recur in 2014) and higher property, franchise and other taxes of $0.7 million (largely due to a reduction in franchise taxes recorded in 2013 that did not recur in 2014). These increases were offset partially by a $3.6 million death benefit gain on life insurance policies that was recorded in 2014, which is recorded in Other Income. In addition, earnings were increased by an increase in income from unconsolidated subsidiaries of $0.4 million (due to the sale of turbine assets held by Horizon Power's investment in ESNE).

2013 Compared with 2012

All Other and Corporate operations recorded a loss of $2.2 million in 2013, which was $4.4 million lower than the loss of $6.6 million in 2012. The decrease in loss was primarily due to lower income tax expense of $3.4 million (primarily due to an intercompany deferred tax reallocation), lower property, franchise and other taxes of $1.8 million (largely due to a reduction in New York State capital stock tax) and a reduction in loss from unconsolidated subsidiaries of $0.8 million (as noted above, a $1.1 million impairment charge was recorded in September 2012 that did not recur in 2013). This was partially offset by higher operating costs of $1.2 million (largely due to higher personnel costs).

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 $0.1 million in 2014 as compared to 2013. This decrease is due to an increase in capitalized interest (mostly in Midstream Corporation) for the year ended September 30, 2014 as compared to the year ended September 30, 2013. This was partially offset by the impact of a higher average amount of long-term debt outstanding (partially offset by a decrease in the weighted average interest on such debt). The Company issued $500 million of 3.75% notes in February 2013 and repaid $250 million of 5.25% notes that matured in March 2013.

Interest on long-term debt increased $8.3 million in 2013 as compared to 2012. This increase is due to a higher average amount of long-term debt outstanding partially offset by a decrease in the weighted average interest rate on such debt. The Company issued $500 million of 3.75% notes in February 2013 and repaid $250 million of 5.25% notes that matured in March 2013. In addition, there was a decrease in capitalized interest associated with decreased Exploration and Production segment capital expenditures in the Appalachian region, which increased interest expense in comparison to the prior year.

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		
	2014	2013	2012
	(Millions)		
Provided by Operating Activities	$909.4	$738.6	$659.0
Capital Expenditures	(914.4)	(703.5)	(1,035.0)
Other Investing Activities	6.0	(2.5)	0.5
Reduction of Long-Term Debt	—	(250.0)	(150.0)
Change in Notes Payable to Banks and Commercial Paper	85.6	(171.0)	131.0
Net Proceeds from Issuance of Long-Term Debt	—	495.4	496.1
Net Proceeds from Issuance of Common Stock	7.5	5.4	10.3
Dividends Paid on Common Stock	(126.7)	(122.7)	(118.8)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	4.6	0.7	1.0
Net Decrease in Cash and Temporary Cash Investments	$(28.0)	$(9.6)	$(5.9)

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, deferred income taxes, stock-based compensation and the elimination of an other post-retirement regulatory liability.

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 $909.4 million in 2014, an increase of $170.8 million compared with the $738.6 million provided by operating activities in 2013. The increase in cash provided by operating activities reflects higher cash provided by operating activities in the Exploration and Production segment, Gathering segment and Corporate category. The increase in the Exploration and Production segment is primarily due to higher cash receipts from natural gas production in the Appalachian region, specifically development in the Marcellus Shale formation. The increase in the Gathering segment is due to an increase in gathering revenues from Midstream Corporation's Trout Run Gathering System and Midstream Corporation's Clermont Gathering System. Lastly, the increase in the Corporate category is primarily due to the receipt of life insurance proceeds.

Net cash provided by operating activities totaled $738.6 million in 2013, an increase of $79.6 million compared with the $659.0 million provided by operating activities in 2012. The increase in cash provided by operating activities reflects higher cash provided by operating activities in the Exploration and Production segment and Pipeline and Storage segment, partly offset by lower cash provided by operating activities in the Utility segment. The increase in the Exploration and Production segment is primarily due to higher cash receipts from natural gas production in the Appalachian region, partially offset by a decrease in cash provided by operating activities from hedging collateral account fluctuations and higher federal and state income tax payments. The increase in the Pipeline and Storage segment is due to higher cash receipts from transportation revenues as a result of expansion projects coming on-line and higher tariff rates from the implementation of Supply Corporation’s rate case proceeding. The decrease in the Utility segment can be attributed to the timing of gas cost recovery and the timing of receivable collections. The winter of 2012 was substantially warmer than normal, resulting in lower receivable balances at September 30, 2012 that were collected in subsequent months. The winter of 2013 saw more normal temperatures, resulting in higher receivable balances at September 30, 2013 that will be collected in subsequent months.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company’s expenditures for long-lived assets totaled $969.9 million, $717.1 million and $977.4 million in 2014, 2013 and 2012, respectively. These amounts include accounts payable and accrued liabilities related to capital expenditures and will differ from capital expenditures shown on the Consolidated Statement of Cash Flows. Capital expenditures recorded as liabilities are excluded from the Consolidated Statement of Cash Flows. They are included in subsequent Consolidated Statement of Cash Flows when they are paid. The table below presents these expenditures:

	Year Ended September 30					
	2014		2013		2012	
	(Millions)					
Exploration and Production:						
Capital Expenditures	$602.7	(1)	$533.1	(2)	$693.8	(3)
Pipeline and Storage:						
Capital Expenditures	139.8	(1)	56.1	(2)	144.2	(3)
Gathering:						
Capital Expenditures	137.8	(1)	54.8	(2)	80.0	(3)
Utility:						
Capital Expenditures	88.8	(1)	72.0	(2)	58.3	(3)
All Other and Corporate:						
Capital Expenditures	0.8		1.1		1.1	
Total Expenditures	$969.9		$717.1		$977.4	

(1) 2014 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $80.1 million, $28.1 million, $20.1 million and $8.3 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(2) 2013 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $58.5 million, $5.6 million, $6.7 million and $10.3 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(3) 2012 capital expenditures for the Exploration and Production segment, Pipeline and Storage segment, the Gathering segment and the Utility segment include $38.9 million, $12.7 million, $12.7 million and $3.2 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

Exploration and Production

In 2014, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $519.9 million for the Appalachian region (including $502.9 million in the Marcellus Shale area) and $82.8 million for the West Coast region. These amounts included approximately $179.9 million spent to develop proved undeveloped reserves.

In 2013, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $428.5 million for the Appalachian region (including $393.3 million in the Marcellus Shale area) and $104.6 million for the West Coast region. These amounts included approximately $148.5 million spent to develop proved undeveloped reserves.

In 2012, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $630.9 million for the Appalachian region (including $567.9 million in the Marcellus Shale area) and $62.9 million for the West Coast region. These amounts included approximately $216.6 million spent to develop proved undeveloped reserves. The capital expenditures in the West Coast region include the Company’s establishment of a position within the Mississippian Lime crude oil play for approximately $6.2 million in August 2012, including approximately 9,300 net acres in Pratt County, Kansas. Seneca is now the operator on 4,600 net acres and has a non-operating interest on the remaining net acreage position.

Pipeline and Storage

The majority of the Pipeline and Storage segment’s capital expenditures for 2014 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 2014 include expenditures related to Supply Corporation’s Mercer Expansion Project ($27.0 million), Supply Corporation’s Northern Access 2015 project ($11.1 million) and Supply Corporation’s Westside Expansion and Modernization Project ($4.8 million), as discussed below.

The majority of the Pipeline and Storage segment's capital expenditures for 2013 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 2013 include expenditures for the construction of Supply Corporation's Northern Access expansion project ($14.5 million), Supply Corporation's Line N 2012 Expansion Project ($4.2 million), Supply Corporation's Line N 2013 Project ($2.8 million) and Supply Corporation's Mercer Expansion Project ($0.7 million).

The majority of the Pipeline and Storage segment's capital expenditures for 2012 were related to the construction of Supply Corporation's Northern Access expansion project ($50.8 million), Supply Corporation's Line N 2012 Expansion Project ($30.5 million), Empire's Tioga County Extension Project ($24.1 million) and Supply Corporation's Line N Expansion Project ($2.9 million). The Pipeline and Storage segment capital expenditures for 2012 also include additions, improvements, and replacements to this segment's transmission and gas storage systems.

Gathering

The majority of the Gathering segment's capital expenditures for 2014 were for the construction of Midstream Corporation's Clermont Gathering System ($95.2 million) and to build compressor stations on Midstream Corporation's Trout Run Gathering System ($32.9 million), as discussed below. In addition, the Gathering segment capital expenditures for 2014 include expenditures for the expansion of Midstream Corporation's Covington Gathering System in Tioga County, Pennsylvania ($4.6 million).

The majority of the Gathering segment's capital expenditures for 2013 were related to the expansion of Midstream Corporation's Trout Run Gathering System ($48.0 million).

The majority of the Gathering segment's capital expenditures for 2012 were related to the construction of Midstream Corporation's Trout Run Gathering System ($64.5 million) and the expansion of Midstream Corporation's Covington Gathering System ($12.2 million).

Utility

The majority of the Utility segment's capital expenditures for 2014, 2013 and 2012 were made for replacement of mains and main extensions and for the replacement of service lines. The capital expenditures for 2014 and 2013 include $15.6 million and $9.1 million, respectively, related to the planned replacement of the Utility segment's legacy mainframe systems, as discussed below.

Estimated Capital Expenditures

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

	Year Ended September 30		
	2015	2016	2017
	(Millions)		
Exploration and Production(1)	$650	$715	$790
Pipeline and Storage	250	480	160
Gathering	175	100	95
Utility	100	80	70
All Other	—	—	—
	$1,175	$1,375	$1,115

(1) Includes estimated expenditures for the years ended September 30, 2015, 2016 and 2017 of approximately $239 million, $81 million and $146 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 2015 for the Exploration and Production segment include approximately $585 million for the Appalachian region and $65 million for the West Coast region.

Estimated capital expenditures in 2016 for the Exploration and Production segment include approximately $645 million for the Appalachian region and $70 million for the West Coast region.

Estimated capital expenditures in 2017 for the Exploration and Production segment include approximately $715 million for the Appalachian region and $75 million for the West Coast region.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2015 through 2017 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 are discussed below.

In light of the growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus and Utica Shale producing area — Supply Corporation and Empire are actively pursuing several expansion projects and paying for preliminary survey and investigation costs, which are initially recorded as Deferred Charges on the Consolidated Balance Sheet. An offsetting reserve is established as those preliminary survey and investigation costs are incurred, which reduces the Deferred Charges balance and increases Operation and Maintenance Expense on the Consolidated Statement of Income. The Company reviews all projects on a quarterly basis, and if it is determined that it is highly probable that the project will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. After the reversal of the reserve, 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. As of September 30, 2014, the total amount reserved for the Pipeline and Storage segment’s preliminary survey and investigation costs was $7.4 million.

Supply Corporation and Empire are moving forward with, or have recently completed, several projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines and to markets beyond the Supply Corporation and Empire pipeline systems. 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 2011, Supply Corporation concluded an Open Season to increase its capability to move gas north on its Line N system and deliver gas to a new interconnection with Tennessee Gas Pipeline ("TGP") at Mercer, Pennsylvania, a pooling point recently established at Tennessee’s Station 219 (“Mercer Expansion Project”). Supply Corporation has executed a service agreement with Range Resources for 105,000 Dth per day, all of the project capacity, for service which began November 1, 2014. The cost estimate is $33.9 million, of which $29.9 million is for expansion and $4.0 million is for system modernization. Supply Corporation has received authorization to construct the required approximately 3,550 horsepower of compression at Mercer, and replace 2.08 miles of 24" pipeline, all under its FERC blanket certificate authorization. As of September 30, 2014, approximately $27.7 million has been capitalized as Construction Work in Progress for the Mercer Expansion Project. The remainder is expected to be spent in fiscal 2015 and is included as Pipeline and Storage estimated capital expenditures in the table above.

On January 18, 2013, Supply Corporation concluded an Open Season to further increase its capacity to move gas north and south on its Line N system to Texas Eastern Transmission, LP (“TETCO”) at Holbrook and TGP at Mercer (“Westside Expansion and Modernization Project”). Supply Corporation executed two precedent agreements for all 175,000 Dth per day of project capacity, for service expected to begin in 2015. The Westside Expansion and Modernization Project facilities are expected to include the replacement of approximately 23.3 miles of 20” pipe with 24” pipe and the addition of approximately 3,550 horsepower of compression at Mercer.

The preliminary cost estimate is $76.2 million, of which $39.6 million is related to expansion and the remainder is for replacement. Supply Corporation filed the FERC 7(c) application in early February 2014 and anticipates a FERC certificate in the second quarter of fiscal 2015. As of September 30, 2014, approximately $4.8 million has been capitalized as Construction Work in Progress for the Westside Expansion and Modernization Project. The remaining expenditures expected to be spent are included as Pipeline and Storage estimated capital expenditures in the table above.

Supply Corporation and TGP have jointly developed a project that will combine expansions on both pipeline systems, providing a seamless transportation path from TGP's 300 Line in the Marcellus fairway to the TransCanada Pipeline delivery point at Niagara. Supply Corporation has offered 140,000 Dth per day of capacity on its system to TGP under a lease, from its Ellisburg Station for redelivery to TGP in East Eden, New York ("Northern Access 2015"). The project will provide Seneca Resources, TGP's anchor shipper, with an outlet to premium Dawn indexed markets in Canada, for their Clermont Area Marcellus production. The Northern Access 2015 project involves the construction of a new 15,400 horsepower compressor station in Hinsdale, New York and a 7,700 horsepower addition to its compressor station in Concord, New York, for service expected to commence in November 2015. Supply Corporation and TGP have executed a precedent agreement incorporating the lease agreement, and both companies filed their respective FERC 7(c) applications in early March 2014 and anticipate a FERC certificate in the first quarter of fiscal 2015. The preliminary cost estimate for the Northern Access 2015 project is $66 million. As of September 30, 2014, approximately $11.1 million has been capitalized as Construction Work in Progress for the Northern Access 2015 project. The remaining expenditures expected to be spent are included in Pipeline and Storage estimated capital expenditures in the table above.

Supply Corporation and Empire have been working with Seneca Resources to develop a project which would move significant prospective Marcellus production from its Western Development Area at Clermont to an interconnection on Empire with TransCanada Pipeline at Chippawa ("Northern Access 2016"). Similar to the Northern Access 2015 project, this project would provide an outlet to premium Dawn indexed markets in Canada in late 2016. The Northern Access 2016 project involves the construction of approximately 101 miles of 24" pipeline and 26,000 horsepower of compression on the two systems. The preliminary cost estimate for the Northern Access 2016 project is $410 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. Seneca Resources executed anchor shipper agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa on this project, and has been awarded the capacity by Supply Corporation and Empire following the close of their respective Open Seasons on June 26, 2014. On July 24, 2014, Supply Corporation and Empire initiated the FERC NEPA Pre-filing process on this project. As of September 30, 2014, approximately $3.7 million has been spent to study the Northern Access 2016 project. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and the project costs have been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

On August 12, 2013, Empire concluded an Open Season, offering for the first time no-notice transportation and storage service to new and existing shippers on the Empire pipeline system. Rochester Gas & Electric ("RG&E"), Empire's largest LDC connected market, has executed a precedent agreement to convert all 172,500 Dth per day of its standard firm transportation services to no-notice service, including 3.3 Bcf of no-notice storage service. The new services will provide RG&E with a superior flexible delivery service with daily and seasonal load balancing capabilities and greater access to Marcellus supplies. In addition, Empire has executed a precedent agreement with New York State Electric and Gas for 14,816 Dth per day of transportation capacity and a third agreement with Distribution Corporation for the remaining 34,500 Dth per day of project capacity, providing both LDCs with increased access to Marcellus supplies. The project would require Empire to construct a 17.2 mile, 12" pipeline and interconnection between Empire's pipeline system and Supply Corporation's system at Tuscarora, New York. It would also require Empire to modify its Oakfield compressor station and require Supply Corporation to construct approximately 1,380 horsepower of compression at its Tuscarora compressor station ("Tuscarora Lateral Project"). Supply Corporation concluded an Open Season and has awarded to Empire the necessary storage services under a lease agreement. Empire and Supply Corporation began the FERC pre-filing process on April 12, 2013, and both companies filed their FERC 7(c) applications in March 2014. The preliminary cost estimate for the Tuscarora Lateral

Project is $45.2 million. As of September 30, 2014, approximately $1.7 million has been

capitalized as Construction Work in Progress for the Tuscarora Lateral Project. The remaining expenditures expected to be spent are included in Pipeline and Storage estimated capital expenditures in the table above.

Empire is developing an expansion of its system that would allow for the transportation of approximately 250,000 Dth per day of additional Marcellus supplies from Millennium Pipeline at Corning or from new interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line ("Central Tioga County Extension"). In addition, the connection to Supply Corporation afforded by the Tuscarora Lateral Project could allow those Marcellus supplies to be sourced from other parts of Supply Corporation. Such a configuration would likely involve facility investments on the Supply Corporation system as well. The preliminary cost estimate for the Central Tioga County Extension is $114 million to $150 million depending on requested receipt points. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2014, approximately $0.2 million has been spent to study the Central Tioga County Extension project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2014.

Gathering

The majority of the Gathering segment capital expenditures in 2015 through 2017 are expected to be for construction and expansion of gathering systems, as discussed below.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, 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 40 miles of backbone and in-field gathering pipelines and two compressor stations. Estimated capital expenditures in 2015 through 2017 include anticipated expenditures in the range of $15 million to $25 million for the continued expansion of the Trout Run Gathering System. As of September 30, 2014, the Company has spent approximately $161.0 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, 2014.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Corporation, is building an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The preliminary cost estimate for the continued buildout is anticipated to be in the range of $250 million to $450 million. As of September 30, 2014, approximately $98.5 million has been spent on the Clermont Gathering System, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2014.

Utility

Capital expenditures for the Utility segment in 2015 through 2017 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. Estimated capital expenditures in the Utility segment for 2015 through 2017 also include amounts for the planned replacement of the Utility segment's legacy mainframe systems. This includes estimated capital expenditures in 2015 of $30.0 million related to the replacement of the customer information system, which is scheduled to be placed in service in the summer of 2015. Estimated capital expenditures for the replacement of other legacy mainframe systems amount to $6.0 million for 2016 and $3.0 million for 2017.

Project Funding

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 and both short and long-term borrowings. Going forward, while the Company expects to use cash from operations as the first means of financing these projects, it is expected that the Company will issue short-term and long-term debt as necessary during fiscal 2015 to help meet its capital expenditure needs. The level of such short-term and long-term borrowings will depend upon the amounts 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

Consolidated short-term debt increased $85.6 million when comparing the balance sheet at September 30, 2014 to the balance sheet at September 30, 2013. The maximum amount of short-term debt outstanding during the year ended September 30, 2014 was $96.3 million. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At September 30, 2014, the Company had outstanding commercial paper of $85.6 million. The Company did not have any outstanding short-term notes payable to banks at September 30, 2014.

The Company maintains a $750.0 million syndicated committed credit facility, which commitment extends through January 6, 2017. As of the date of filing of this Form 10-K, the Company is pursuing options to refinance this facility with a substantially similar syndicated committed credit facility. The Company expects the new credit facility would total $750.0 million and would extend for five years from the date the parties enter into it. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines.

The total amount available to be issued under the Company's commercial paper program is $300.0 million. At September 30, 2014, the commercial paper program was backed by the $750.0 million syndicated committed credit facility. Under the committed credit facility, the Company agreed that its debt to capitalization ratio would not exceed .65 at the last day of any fiscal quarter through January 6, 2017. At September 30, 2014, the Company's debt to capitalization ratio (as calculated under the facility) was .42. The constraints specified in the committed credit facility would have permitted an additional $2.74 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

The Company's $750.0 million committed credit facility 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 committed credit facility. 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, 2014, the Company did not have any debt outstanding under the committed credit facility.

Under the Company's existing indenture covenants, at September 30, 2014, the Company would have been permitted to issue up to a maximum of $1.92 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company's ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt.

The Company's 1974 indenture pursuant to which $99.0 million (or 6.0%) of the Company's long-term debt (as of September 30, 2014) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's embedded cost of long-term debt was 5.58% at both September 30, 2014 and September 30, 2013. Refer to "Interest Rate Risk" in this Item for a more detailed breakdown of the Company's embedded cost of long-term debt.

None of the Company's long-term debt at September 30, 2014 and 2013 had a maturity date within the following twelve-month period.

On February 15, 2013, the Company issued $500.0 million of 3.75% notes due March 1, 2023. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $495.4 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used to refund the $250.0 million of 5.25% notes that matured in March 2013, as well as for general corporate purposes, including the reduction of short-term debt.

On December 1, 2011, the Company issued $500.0 million of 4.90% notes due December 1, 2021. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $496.1 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including refinancing short-term debt that was used to pay the $150.0 million due at the maturity of the Company's 6.70% notes in November 2011.

The Company may issue debt or equity securities in a public offering or a private placement from time to time. The amounts and timing of the issuance and sale of debt or equity securities will depend on market conditions, indenture requirements, regulatory authorizations and the capital requirements of the Company.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company's consolidated subsidiaries have operating leases, the majority of which are with the Exploration and Production segment and Corporate operations, having a remaining lease commitment of approximately $40.8 million. These leases have been entered into for the use of compressors, drilling rigs, buildings, meters and other items and are accounted for as operating leases.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2014, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2015	2016	2017	2018	2019	Thereafter	Total
	(Millions)						
Long-Term Debt, including interest expense(1)	$91.9	$91.9	$91.9	$383.0	$313.3	$1,249.9	$2,221.9
Operating Lease Obligations	$16.0	$5.8	$5.7	$5.6	$5.3	$2.4	$40.8
Purchase Obligations:							
Gas Purchase Contracts(2)	$217.1	$2.5	$1.0	$—	$—	$—	$220.6
Transportation and Storage Contracts(3)	$46.7	$64.2	$90.8	$91.8	$82.1	$845.1	$1,220.7
Hydraulic Fracturing and Fuel Obligations	$95.3	$24.0	$0.2	$—	$—	$—	$119.5
Pipeline, Compressor and Gathering Projects	$103.9	$0.5	$—	$—	$—	$—	$104.4
Mainframe Replacement Project	$21.0	$5.0	$—	$—	$—	$—	$26.0
Other	$14.5	$9.9	$6.3	$2.7	$2.7	$2.2	$38.3

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

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

(3) Transportation service contractual obligations include the following precedent agreements executed by the Exploration and Production segment for transportation of Appalachian gas: zero for 2015, $13.8 million for 2016, $42.9 million for 2017, $45.0 million for 2018, $55.5 million for 2019 and $797.7 million thereafter.

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

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the Consolidated Balance Sheets in accordance with the authoritative guidance (see Item 7, MD&A under the heading "Critical Accounting Estimates — Accounting for Derivative Financial Instruments"); (ii) NFR obligations to purchase gas or to purchase gas transportation/storage services where the amounts due on those obligations each month are included on the Consolidated Balance Sheets as a current liability; and (iii) other obligations which are reflected on the Consolidated Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note I — Commitments and Contingencies, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows

in the period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan). The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it will continue making contributions to the Retirement Plan. During 2014, the Company contributed $33.5 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2015 will be in the range of $15.0 million to $25.0 million.

Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in 2015 in order to be in compliance with the Pension Protection Act of 2006 (as impacted by the Moving Ahead for Progress in the 21st Century Act). In July 2012, the Surface Transportation Extension Act, which is also referred to as the Moving Ahead for Progress in the 21st Century Act (the Act), was passed by Congress and signed by the President. The Act included pension funding stabilization provisions. The Highway and Transportation Funding Act of 2014 (HAFTA) was passed by Congress on July 2014 and signed by the President in August 2014. HAFTA extended certain funding stabilization provisions of the Act signed into law in 2012. The Company is continually evaluating its future contributions in light of the provisions of these laws. The Company expects that all subsidiaries having employees covered by the Retirement Plan will make contributions to the Retirement Plan. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments or through short-term borrowings or cash from operations.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The Company has established VEBA trusts and 401(h) accounts for its other post-retirement benefits. The Company has been making contributions to its VEBA trusts and 401(h) accounts over the last several years and anticipates that it will continue making contributions to the VEBA trusts and 401(h) accounts. During 2014, the Company contributed $2.0 million to its VEBA trusts and 401(h) accounts. The Company anticipates that the annual contribution to its VEBA trusts and 401(h) accounts in 2015 will be in the range of $2.0 million to $5.0 million. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.

In January 2014, Seneca entered into a precedent agreement with Transcontinental Pipe Line Company, LLC (Transcontinental) whereby Transcontinental will provide 189,405 Dth per day of firm natural gas transportation service to Seneca on Transcontinental's proposed Atlantic Sunrise Project. The proposed Atlantic Sunrise Project involves the construction of approximately 120 miles of new natural gas pipeline extending from Transcontinental's Leidy Line in Columbia County, Pennsylvania to an interconnection with Transcontinental's mainline in Lancaster County, Pennsylvania. The targeted in-service date for the proposed pipeline facilities is September 2017.

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company uses various derivative financial instruments (derivatives), including price swap agreements and futures contracts, as part of the Company's overall energy commodity price risk management strategy in its Exploration and Production and Energy Marketing segments. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from, or pay to, the respective counterparties at September 30, 2014 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial instruments.

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the

law. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as “swap dealers” and “major swap participants,” (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC’s enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, the CFTC has imposed numerous registration, swaps documentation, business conduct, reporting, and recordkeeping requirements on swap dealers and major swap participants, which frequently are counterparties to the Company’s derivative hedging transactions. Similarly, the CFTC and various banking regulators have proposed rules that would require swap dealers and major swap participants subject to their jurisdiction to comply with certain obligations relating to capitalization and the collection of initial and variation margin from certain counterparties, although the recent proposals do not mandate the collection of margin from counterparties that qualify as non-financial end users, such as the Company. Regardless of the final capital and margin rules, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from the final and proposed rules through higher transaction costs and prices or other direct or indirect costs. In addition, while the Company expects to be exempt from the Dodd-Frank Act’s requirement that certain swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, documentation, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company’s ability to monetize or restructure existing derivative contracts; and increase the Company’s exposure to less creditworthy counterparties, all of which could increase the Company’s business costs. The Company continues to monitor these developments but cannot predict the impact the Dodd-Frank Act may ultimately have on its operations.

In accordance with the authoritative guidance for fair value measurements, the Company has identified certain inputs used to recognize fair value as Level 3 (unobservable inputs). The Level 3 derivative net assets (at September 30, 2014) and net liabilities (at September 30, 2013) relate to crude oil swap agreements used to hedge forecasted sales at a specific location (southern California). The Company’s internal model that is used to calculate fair value applies a historical basis differential (between the sales locations and NYMEX) to a forward NYMEX curve because there is not a forward curve specific to this sales location. The Company does not believe that the fair value recorded would be significantly different from what it expects to receive upon settlement.

The Company uses the crude oil swaps classified as Level 3 to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative net assets (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities. The Level 3 derivative net assets amount to $1.4 million at September 30, 2014 and represent 1.0% of the Total Net Assets shown in Item 8 at Note F — Fair Value Measurements at September 30, 2014.

The change from a net fair value liability to a net fair value asset of the Level 3 positions from October 1, 2013 to September 30, 2014, as shown in Item 8 at Note F, was attributable to a decrease in the commodity price of crude oil relative to the swap prices during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at September 30, 2014.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2014, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company

considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company's (for a liability) credit default swaps rates.

The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2014. At September 30, 2014, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2018.

Natural Gas Price Swap Agreements

	Expected Maturity Dates				
	2015	2016	2017	2018	Total
Notional Quantities (Equivalent Bcf)	92.6	63.0	44.8	5.3	205.7
Weighted Average Fixed Rate (per Mcf)	$4.26	$4.30	$4.46	$4.81	$4.33
Weighted Average Variable Rate (per Mcf)	$3.90	$3.94	$4.11	$4.49	$3.97

Of the total Bcf above, 0.5 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $4.41 per Mcf. The remaining 205.2 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $4.33 per Mcf.

Crude Oil Price Swap Agreements

	Expected Maturity Dates				
	2015	2016	2017	2018	Total
Notional Quantities (Equivalent Bbls)	1,557,000	1,269,000	384,000	75,000	3,285,000
Weighted Average Fixed Rate (per Bbl)	$95.27	$92.95	$92.30	$91.00	$93.93
Weighted Average Variable Rate (per Bbl)	$93.29	$94.00	$95.54	$94.58	$93.85

At September 30, 2014, the Company would have received from its respective counterparties an aggregate of approximately $71.5 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have to pay its respective counterparties an aggregate of approximately $0.3 million to terminate the crude oil price swap agreements outstanding at September 30, 2014.

At September 30, 2013, the Company had natural gas price swap agreements covering 213.8 Bcf at a weighted average fixed rate of $4.33 per Mcf. The Company also had crude oil price swap agreements covering 4,299,000 Bbls at a weighted average fixed rate of $96.39 per Bbl.

The following table discloses the net contract volume purchased (sold), weighted average contract prices and weighted average settlement prices by expected maturity date for futures contracts used to manage natural gas price risk. At September 30, 2014, the Company did not hold any futures contracts with maturity dates extending beyond 2018.

Futures Contracts

	Expected Maturity Dates				
	2015	2016	2017	2018	Total
Net Contract Volume Purchased (Sold) (Equivalent Bcf)	6.8	3.2	0.3	0.1	10.4
Weighted Average Contract Price (per Mcf)	$4.37	$4.40	$4.58	$4.68	$4.40
Weighted Average Settlement Price (per Mcf)	$4.36	$4.42	$4.56	$4.77	$4.40

At September 30, 2014, the Company had long (purchased) contracts covering 18.1 Bcf of gas extending through 2018 at a weighted average contract price of $4.30 per Mcf and a weighted average settlement price of $4.23 per Mcf. Of this amount, 15.2 Bcf is accounted for as fair value hedges and are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with certain residential, commercial, industrial, public authority and wholesale customers. The remaining 2.9 Bcf is accounted for as cash flow hedges used to hedge against rising prices related to anticipated gas purchases for potential injections into storage. The Company would have paid $1.3 million to terminate these contracts at September 30, 2014.

At September 30, 2014, the Company had short (sold) contracts covering 7.7 Bcf of gas extending through 2018 at a weighted average contract price of $4.64 per Mcf and a weighted average settlement price of $4.46 per Mcf. Of this amount, 7.3 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Company's Energy Marketing segment. The remaining 0.4 Bcf is accounted for as fair value hedges, the majority of which are used to hedge against falling prices, a risk to which the Energy Marketing segment is exposed due to the fixed price gas purchase commitments that it enters into with certain natural gas suppliers. The Company would have received $1.4 million to terminate these contracts at September 30, 2014.

At September 30, 2013, the Company had long (purchased) contracts covering 8.7 Bcf of gas extending through 2017 at a weighted average contract price of $4.19 per Mcf and a weighted average settlement price of $4.02 per Mcf.

At September 30, 2013, the Company had short (sold) contracts covering 7.3 Bcf of gas extending through 2016 at a weighted average contract price of $4.33 per Mcf and a weighted average settlement price of $4.00 per Mcf.

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

Interest Rate Risk

The fair value of long-term fixed rate debt is $1.8 billion at September 30, 2014. This fair value amount is not intended to reflect principal amounts that the Company will ultimately be required to pay. The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company's long-term fixed rate debt:

	Principal Amounts by Expected Maturity Dates						
	2015	2016	2017	2018	2019	Thereafter	Total
	(Dollars in millions)						
Long-Term Fixed Rate Debt	$—	$—	$—	$300.0	$250.0	$1,099.0	$1,649.0
Weighted Average Interest Rate Paid	—	—	—	6.5 %	8.8 %	4.6 %	5.6 %

RATE AND REGULATORY MATTERS

Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states' respective public utility commissions and typically are changed only when approved through a procedure known as a "rate case." Although neither division has a rate case on file, see below for a description of other rate proceedings affecting the New York division. In both jurisdictions, delivery rates do not reflect the recovery of purchased gas costs. Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated "supply charge" on the customer bill.

New York Jurisdiction

Customer delivery rates charged by Distribution Corporation's New York division were established in a rate order issued on December 21, 2007 by the NYPSC. In connection with an efficiency and conservation program,

the rate order approved a revenue decoupling mechanism. The revenue decoupling mechanism “decouples” revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation.

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an “earnings sharing mechanism” (“ESM”). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation’s pipeline replacement spending by $8.2 million per year. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. The Consolidated Balance Sheet at September 30, 2013 reflected a $7.5 million ($4.9 million after-tax) refund provision related to the settlement agreement. This amount was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014.

Pennsylvania Jurisdiction

Distribution Corporation’s current delivery charges in its Pennsylvania jurisdiction were approved by the PaPUC on November 30, 2006 as part of a settlement agreement that became effective January 1, 2007.

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. A rate settlement approved by the FERC on August 6, 2012 requires Supply Corporation to make a general rate filing no later than January 1, 2016. In addition, Supply Corporation is not barred from filing a general rate case before such date or at any time.

Empire also has no rate case currently on file with the FERC, but is not subject to any requirement to make any future general rate filing. Empire is also not barred from filing a general rate case at any time.

ENVIRONMENTAL MATTERS

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory requirements.

For further discussion of the Company's environmental exposures, refer to Item 8 at Note I — Commitments and Contingencies under the heading “Environmental Matters.”

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. In the United States, these efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation related to greenhouse gas emissions. While the U.S. Congress has from time to time considered legislation aimed at reducing emissions of greenhouse gases, Congress has not yet passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating greenhouse gas emissions pursuant to the authority granted to it by the federal Clean Air Act. For example, in April 2012, the EPA adopted rules which restrict emissions associated with oil and natural gas drilling. Compliance with these rules will not materially change the Company’s ongoing emissions–limiting technologies and practices, and is not expected to have a significant impact on the Company. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts carbon emissions could increase the Company’s cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard

to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

NEW AUTHORITATIVE ACCOUNTING AND FINANCIAL REPORTING GUIDANCE

For discussion of the recently issued authoritative accounting and financial reporting guidance, refer to Item 8 at Note A — Summary of Significant Accounting Policies under the heading “New Authoritative Accounting and Financial Reporting Guidance.”

EFFECTS OF INFLATION

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

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

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

1. Factors affecting the Company’s ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;
2. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
3. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;

4. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;
5. Changes in the price of natural gas or oil;
6. Changes in price differential between similar quantities of natural gas or oil at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations;
7. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;
8. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
9. Uncertainty of oil and gas reserve estimates;
10. Significant differences between the Company's projected and actual production levels for natural gas or oil;
11. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;
12. Changes in demographic patterns and weather conditions;
13. Changes in the availability, price or accounting treatment of derivative financial instruments;
14. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company's ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company's credit ratings and changes in interest rates and other capital market conditions;
15. Changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers' ability to pay for, the Company's products and services;
16. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;
17. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;
18. Significant differences between the Company's projected and actual capital expenditures and operating expenses;
19. Changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company's pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;
20. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or
21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

Item 7A Quantitative and Qualitative Disclosures About Market Risk

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

Item 8 Financial Statements and Supplementary Data

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

Supplementary Data

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2014 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2014, based on criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

/s/ PRICEWATERHOUSECOOPERS LLP

Buffalo, New York

November 21, 2014

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

	Year Ended September 30		
	2014	2013	2012
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$2,113,081	$1,829,551	$1,626,853
Operating Expenses			
Purchased Gas	605,838	460,432	415,589
Operation and Maintenance	463,078	442,090	401,397
Property, Franchise and Other Taxes	90,711	82,431	90,288
Depreciation, Depletion and Amortization	383,781	326,760	271,530
	1,543,408	1,311,713	1,178,804
Operating Income	569,673	517,838	448,049
Other Income (Expense):			
Other Income	9,461	4,697	5,133
Interest Income	4,170	4,335	3,689
Interest Expense on Long-Term Debt	(90,194)	(90,273)	(82,002)
Other Interest Expense	(4,083)	(3,838)	(4,238)
Income Before Income Taxes	489,027	432,759	370,631
Income Tax Expense	189,614	172,758	150,554
Net Income Available for Common Stock	299,413	260,001	220,077
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	1,442,617	1,306,284	1,206,022
	1,742,030	1,566,285	1,426,099
Dividends on Common Stock	(127,669)	(123,668)	(119,815)
Balance at End of Year	$1,614,361	$1,442,617	$1,306,284
Earnings Per Common Share:			
Basic:			
Net Income Available for Common Stock	$3.57	$3.11	$2.65
Diluted:			
Net Income Available for Common Stock	$3.52	$3.08	$2.63
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	83,929,989	83,518,857	83,127,844
Used in Diluted Calculation	84,952,347	84,341,220	83,739,771

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2014	2013	2012
	(Thousands of dollars)		
Net Income Available for Common Stock	$299,413	$260,001	$220,077
Other Comprehensive Income (Loss), Before Tax:			
Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(8,280)	55,940	(27,552)
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	9,203	15,282	10,270
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	3,863	5,041	3,545
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	5,334	91,790	(7,248)
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	(662)	—	—
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	17,647	(36,029)	(65,691)
Other Comprehensive Income (Loss), Before Tax	27,105	132,024	(86,676)
Income Tax Expense (Benefit) Related to the Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(2,720)	21,304	(10,144)
Reclassification Adjustment for Income Tax Benefit Related to the Amortization of the Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	3,370	5,650	3,836
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	1,398	1,847	1,311
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	529	38,236	(8,244)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	(242)	—	—
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	9,515	(14,799)	(22,114)
Income Taxes — Net	11,850	52,238	(35,355)
Other Comprehensive Income (Loss)	15,255	79,786	(51,321)
Comprehensive Income	$314,668	$339,787	$168,756

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY
CONSOLIDATED BALANCE SHEETS

	At September 30	
	2014	2013
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$8,245,791	$7,313,203
Less — Accumulated Depreciation, Depletion and Amortization	2,502,700	2,161,477
	5,743,091	5,151,726
Current Assets		
Cash and Temporary Cash Investments	36,886	64,858
Hedging Collateral Deposits	2,734	1,094
Receivables — Net of Allowance for Uncollectible Accounts of $31,811 and $27,144, Respectively	149,735	133,182
Unbilled Revenue	25,663	19,483
Gas Stored Underground	39,422	51,484
Materials and Supplies — at average cost	27,817	29,904
Unrecovered Purchased Gas Costs	—	12,408
Other Current Assets	54,752	56,905
Deferred Income Taxes	40,323	79,359
	377,332	448,677
Other Assets		
Recoverable Future Taxes	163,485	163,355
Unamortized Debt Expense	14,304	16,645
Other Regulatory Assets	224,436	252,568
Deferred Charges	14,212	9,382
Other Investments	86,788	96,308
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	36,512	22,774
Fair Value of Derivative Financial Instruments	72,606	48,989
Other	1,355	2,447
	619,174	617,944
Total Assets	$6,739,597	$6,218,347
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value; Authorized - 200,000,000 Shares; Issued and Outstanding - 84,157,220 Shares and 83,661,969 Shares, Respectively	$84,157	$83,662
Paid In Capital	716,144	687,684
Earnings Reinvested in the Business	1,614,361	1,442,617
Accumulated Other Comprehensive Loss	(3,979)	(19,234)
Total Comprehensive Shareholders' Equity	2,410,683	2,194,729
Long-Term Debt, Net of Current Portion	1,649,000	1,649,000
Total Capitalization	4,059,683	3,843,729
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	85,600	—
Current Portion of Long-Term Debt	—	—
Accounts Payable	136,674	105,283

Amounts Payable to Customers	33,745	12,828
Dividends Payable	32,400	31,373
Interest Payable on Long-Term Debt	29,960	29,960
Customer Advances	19,005	21,959
Customer Security Deposits	15,761	16,183
Other Accruals and Current Liabilities	136,672	83,946
Fair Value of Derivative Financial Instruments	759	639
	490,576	302,171
Deferred Credits		
Deferred Income Taxes	1,456,283	1,347,007
Taxes Refundable to Customers	91,736	85,655
Unamortized Investment Tax Credit	1,145	1,579
Cost of Removal Regulatory Liability	173,199	157,622
Other Regulatory Liabilities	81,152	61,549
Pension and Other Post-Retirement Liabilities	134,202	158,014
Asset Retirement Obligations	117,713	119,511
Other Deferred Credits	133,908	141,510
	2,189,338	2,072,447
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$6,739,597	$6,218,347

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2014	2013	2012
	(Thousands of dollars)		
Operating Activities			
Net Income Available for Common Stock	$299,413	$260,001	$220,077
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Depreciation, Depletion and Amortization	383,781	326,760	271,530
Deferred Income Taxes	142,415	167,887	144,150
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(4,641)	(675)	(985)
Elimination of Other Post-Retirement Regulatory Liability	—	—	(21,672)
Stock-Based Compensation	11,763	12,446	7,939
Other	14,063	14,965	5,013
Change in:			
Hedging Collateral Deposits	(1,640)	(730)	19,337
Receivables and Unbilled Revenue	(22,781)	(17,135)	13,859
Gas Stored Underground and Materials and Supplies	13,285	(3,016)	5,405
Unrecovered Purchased Gas Costs	12,408	(12,408)	—
Other Current Assets	(3,630)	(109)	9,790
Accounts Payable	15,149	8,303	(16,773)
Amounts Payable to Customers	20,917	(7,136)	4,445
Customer Advances	(2,954)	(2,096)	4,412
Customer Security Deposits	(422)	(1,759)	621
Other Accruals and Current Liabilities	6,872	666	10,633
Other Assets	18,513	(5,757)	(4,396)
Other Liabilities	6,879	(1,635)	(14,375)
Net Cash Provided by Operating Activities	909,390	738,572	659,010
Investing Activities			
Capital Expenditures	(914,417)	(703,461)	(1,035,007)
Other	5,982	(2,522)	446
Net Cash Used in Investing Activities	(908,435)	(705,983)	(1,034,561)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	85,600	(171,000)	131,000
Excess Tax Benefits Associated with Stock-Based Compensation Awards	4,641	675	985
Net Proceeds from Issuance of Long-Term Debt	—	495,415	496,085
Reduction of Long-Term Debt	—	(250,000)	(150,000)
Net Proceeds from Issuance of Common Stock	7,474	5,395	10,345
Dividends Paid on Common Stock	(126,642)	(122,710)	(118,798)
Net Cash Provided By (Used in) Financing Activities	(28,927)	(42,225)	369,617
Net Decrease in Cash and Temporary Cash Investments	(27,972)	(9,636)	(5,934)
Cash and Temporary Cash Investments At Beginning of Year	64,858	74,494	80,428
Cash and Temporary Cash Investments At End of Year	$36,886	$64,858	$74,494
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			

Interest	$91,927	$91,215	$79,820
Income Taxes	$40,944	$13,187	$474
Non-Cash Investing Activities:			
Non-Cash Capital Expenditures	$136,628	$81,138	$67,503

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A — Summary of Significant Accounting Policies

Principles of Consolidation

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

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

Regulation

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

Revenue Recognition

The Company’s Exploration and Production segment records revenue based on entitlement, which means that revenue is recorded based on the actual amount of gas or oil that is delivered to a pipeline and the Company’s ownership interest in the producing well. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance.

The Company’s Pipeline and Storage segment records revenue for natural gas transportation and storage services. Revenue from reservation charges on firm contracted capacity is recognized through equal monthly charges over the contract period regardless of the amount of gas that is transported or stored. Commodity charges on firm contracted capacity and interruptible contracts are recognized as revenue when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage field. The point of delivery into the pipeline or injection or withdrawal from storage is the point at which ownership and risk of loss transfers to the buyer of such transportation and storage services.

In the Company’s Gathering segment, revenue is recorded at the point at which gathered volumes are delivered into interstate pipelines.

The Company’s Utility segment records revenue for gas sales and transportation in the period that gas is delivered to customers. This includes the recording of receivables for gas delivered but not yet billed to customers based on the Company's estimate of the amount of gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets.

The Company’s Energy Marketing segment records revenue for gas sales in the period that gas is delivered to customers. This includes the recording of receivables for gas delivered but not yet billed to customers based on the Company's estimate of the amount of gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets.

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

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The allowance is determined based on historical experience, the age and other specific information about customer accounts. Account balances are charged off against the allowance twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered.

Regulatory Mechanisms

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

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

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

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

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

Property, Plant and Equipment

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

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

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2014, 2013, and 2012, estimated future net cash flows were decreased by $33.6 million and increased by $71.6 million and $128.4 million, respectively. At September 30, 2014, the ceiling exceeded the book value of the oil and gas properties by approximately $148.4 million.

The principal assets of the Utility and Pipeline and Storage segments, consisting primarily of gas plant in service, are recorded at the historical cost when originally devoted to service.

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

Depreciation, Depletion and Amortization

For oil and gas properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unproved oil and gas properties is excluded from this computation. In the All Other category, for timber properties, depletion, determined on a property by property basis, is charged to operations based on the actual amount of timber cut in relation to the total amount of recoverable timber. For all other property, plant and equipment, depreciation and amortization is computed using the straight-line method in amounts sufficient to recover costs over the estimated service lives of property in service. The following is a summary of depreciable plant by segment:

	As of September 30	
	2014	2013
	(Thousands)	
Exploration and Production	$3,996,834	$3,437,767
Pipeline and Storage	1,609,593	1,547,192
Gathering	239,507	130,082
Utility	1,833,104	1,778,140
Energy Marketing	3,366	3,460
All Other and Corporate	108,986	109,690
	$7,791,390	$7,006,331

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

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30					
	2014		2013		2012	
Exploration and Production, per Mcfe(1)	$1.85		$2.02		$2.25	
Pipeline and Storage	2.4	%	2.5	%	2.9	%
Gathering	3.3	%	3.7	%	3.3	%
Utility	2.6	%	2.6	%	2.6	%
Energy Marketing	5.8	%	3.9	%	3.6	%
All Other and Corporate	0.9	%	1.3	%	1.1	%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note M — Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $1.82, $1.98 and $2.19 per Mcfe of production in 2014, 2013 and 2012, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2014 and 2013 on its Consolidated Balance Sheets related to the Company's acquisition of Empire in 2003. The Company accounts for goodwill in accordance with the current authoritative guidance, which requires the Company to test goodwill for impairment annually. At September 30, 2014, 2013 and 2012, the fair value of Empire was greater than its book value. As such, the goodwill was not considered impaired at those dates. Going back to the origination of the goodwill in 2003, the Company has never recorded an impairment of its goodwill balance.

Financial Instruments

Unrealized gains or losses from the Company's investments in an equity mutual fund and the stock of an insurance company (securities available for sale) are recorded as a component of accumulated other comprehensive income (loss). Reference is made to Note G — Financial Instruments for further discussion.

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. These instruments include price swap agreements and futures contracts. The Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled Fair Value of Derivative Financial Instruments. Reference is made to Note F — Fair Value Measurements for further discussion concerning the fair value of derivative financial instruments.

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

For fair value hedges, the offset to the asset or liability that is recorded is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheets representing the change in fair value of the asset or firm commitment that is being hedged (see Other Current Assets section in this footnote). The offset to this asset or liability is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income as well. If the fair value hedge is effective, the gain or loss from the derivative financial instrument is offset by the gain or loss that arises from the change in fair value of the asset or firm

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

commitment that is being hedged. Reference is made to Note G - Financial Instruments for further discussion concerning fair value hedges.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) and changes for the year ended September 30, 2014, net of related tax effect, are as follows (amounts in parentheses indicate debits) (in thousands):

	Gains and Losses on Derivative Financial Instruments	Gains and Losses on Securities Available for Sale	Funded Status of the Pension and Other Post-Retirement Benefit Plans	Total
Year Ended September 30, 2014				
Balance at October 1, 2013	$30,722	$6,337	$(56,293)	$(19,234)
Other Comprehensive Gains and Losses Before Reclassifications	4,805	2,465	(5,560)	1,710
Amounts Reclassified From Other Comprehensive Loss	8,132	(420)	5,833	13,545
Balance at September 30, 2014	$43,659	$8,382	$(56,020)	$(3,979)

The amounts included in accumulated other comprehensive income (loss) related to the funded status of the Company’s pension and other post-retirement benefit plans consist of prior service costs and accumulated losses. The total amount for prior service credit was $0.2 million and $0.3 million at September 30, 2014 and 2013, respectively. The total amount for accumulated losses was $56.2 million and $56.6 million at September 30, 2014 and 2013, respectively.

Reclassifications Out of Accumulated Other Comprehensive Loss

The details about the reclassification adjustments out of accumulated other comprehensive loss for the year ended September 30, 2014 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Loss Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Loss for the Year Ended September 30, 2014	Affected Line Item in the Statement Where Net Income is Presented
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:		
Commodity Contracts	($14,880)	Operating Revenues
Commodity Contracts	(2,767)	Purchased Gas
Gains (Losses) on Securities Available for Sale	662	Other Income
Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans:		
Prior Service Credit	131	(1)
Net Actuarial Loss	(9,334)	(1)
	(26,188)	Total Before Income Tax
	12,643	Income Tax Expense
	($13,545)	Net of Tax

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

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

Gas Stored Underground — Current

In the Utility segment, gas stored underground — current in the amount of $25.3 million is carried at lower of cost or market, on a LIFO method. Based upon the average price of spot market gas purchased in September 2014, including transportation costs, the current cost of replacing this inventory of gas stored underground — current exceeded the amount stated on a LIFO basis by approximately $33.2 million at September 30, 2014. All other gas stored underground — current, which is in the Energy Marketing segment, is carried at an average cost method, subject to lower of cost or market adjustments.

Unamortized Debt Expense

Costs associated with the issuance of debt by the Company are deferred and amortized over the lives of the related debt.

Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment. At September 30, 2014, the remaining weighted average amortization period for such costs was approximately 5 years.

Income Taxes

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

Investment tax credit, prior to its repeal in 1986, was deferred and is being amortized over the estimated useful lives of the related property, as required by regulatory authorities having jurisdiction.

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

Consolidated Statement of Cash Flows

For purposes of the Consolidated Statement of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of generally three months or less to be cash equivalents.

Hedging Collateral Deposits

This is an account title for cash held in margin accounts funded by the Company to serve as collateral for hedging positions. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instrument liability or asset balances.

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

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

	Year Ended September 30	
	2014	2013
	(Thousands)	
Prepayments	$10,079	$10,605
Prepaid Property and Other Taxes	13,743	13,079
Federal Income Taxes Receivable	8,211	1,122
State Income Taxes Receivable	—	3,275
Fair Values of Firm Commitments	—	1,829
Regulatory Assets	22,719	26,995
	$54,752	$56,905

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

	Year Ended September 30	
	2014	2013
	(Thousands)	
Accrued Capital Expenditures	$80,348	$41,100
Regulatory Liabilities	18,072	20,013
State Income Taxes Payable	5,798	—
Other	32,454	22,833
	$136,672	$83,946

Customer Advances
The Company's Utility and Energy Marketing segments have balanced billing programs whereby customers pay their estimated annual usage in equal installments over a twelve-month period. Monthly payments under the balanced billing programs are typically higher than current month usage during the summer months. During the winter months, monthly payments under the balanced billing programs are typically lower than current month usage. At September 30, 2014 and 2013, customers in the balanced billing programs had advanced excess funds of $19.0 million and $22.0 million, respectively.

Customer Security Deposits
The Company, in its Utility, Pipeline and Storage, and Energy Marketing segments, often times requires security deposits from marketers, producers, pipeline companies, and commercial and industrial customers before providing services to such customers. At September 30, 2014 and 2013, the Company had received customer security deposits amounting to $15.8 million and $16.2 million, respectively.

Earnings Per Common Share
Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options, SARs, restricted stock units and performance shares.

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

The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. Stock options, SARs, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2014, 2013 and 2012, 1,007 securities, 181,418 securities and 844,872 securities were excluded as being antidilutive, respectively.

Stock-Based Compensation

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

Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. The market value of restricted stock on the date of the award is recorded as compensation expense over the vesting period. Certificates for shares of restricted stock awarded under the Company's stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant. Restricted stock units also are subject to restrictions on vesting and transferability. Restricted stock units, both performance and non-performance based, represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. The performance based and non-performance based restricted stock units do not entitle the participants to dividend and voting rights. The accounting for performance based and non-performance based restricted stock units is the same as the accounting for restricted share awards, except that the fair value at the date of grant of the restricted stock units (represented by the market value of Company common stock on the date of the award) must be reduced by the present value of forgone dividends over the vesting term of the award. The fair value of restricted stock units on the date of award is recorded as compensation expense over the vesting period.

Performance shares are an award constituting units denominated in common stock of the Company, the number of which may be adjusted over a performance cycle based upon the extent to which performance goals have been satisfied. Earned performance shares may be distributed in the form of shares of common stock of the Company, an equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company. The performance shares do not entitle the participant to receive dividends during the vesting period. For performance shares based on a return on capital goal, the fair value at the date of grant of the performance shares is determined by multiplying the expected number of performance shares to be issued by the market value of Company common stock on the date of grant reduced by the present value of forgone dividends. For performance shares based on a total shareholder return goal, the Company uses the Monte Carlo simulation technique to estimate the fair value price at the date of grant.

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

New Authoritative Accounting and Financial Reporting Guidance

In May 2014, the FASB issued authoritative guidance regarding revenue recognition. The authoritative guidance provides a single, comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement

of revenue and timing of when it is recognized. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2018 and early adoption is not permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements and disclosures.

In June 2014, the FASB issued authoritative guidance regarding accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the employee has completed the requisite service period. This authoritative guidance requires that such performance targets that affect vesting be treated as performance conditions, meaning that the performance target should not be factored in the calculation of the award at the grant date. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2017, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

Note B — Asset Retirement Obligations

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

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

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

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

A reconciliation of the Company's asset retirement obligations are shown below:

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Balance at Beginning of Year	$119,511	$119,246	$75,731
Liabilities Incurred and Revisions of Estimates	(2,496)	(4,796)	41,653
Liabilities Settled	(6,955)	(1,744)	(2,997)
Accretion Expense	7,653	6,805	4,859
Balance at End of Year	$117,713	$119,511	$119,246

Note C — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2014	2013
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note H)	$164,804	$187,181
Post-Retirement Benefit Costs(2) (Note H)	17,128	29,838
Recoverable Future Taxes (Note D)	163,485	163,355
Environmental Site Remediation Costs(2) (Note I)	25,645	18,104
NYPSC Assessment(3)	12,730	13,169
Asset Retirement Obligations(2) (Note B)	12,006	11,837
Unamortized Debt Expense (Note A)	2,747	3,276
Other(4)	14,842	19,434
Total Regulatory Assets	413,387	446,194
Less: Amounts Included in Other Current Assets	(22,719)	(26,995)
Total Long-Term Regulatory Assets	$390,668	$419,199

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

	At September 30	
	2014	2013
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	$173,199	$157,622
Taxes Refundable to Customers (Note D)	91,736	85,655
Post-Retirement Benefit Costs (Note H)	53,650	37,923
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	33,745	12,828
Off-System Sales and Capacity Release Credits(5)	12,805	10,228
Other(6)	32,769	33,411
Total Regulatory Liabilities	397,904	337,667
Less: Amounts included in Current and Accrued Liabilities	(51,817)	(32,841)
Total Long-Term Regulatory Liabilities	$346,087	$304,826

(1) The Company recovers the cost of its regulatory assets but generally does not earn a return on them. There are a few exceptions to this rule. For example, the Company does earn a return on Unrecovered Purchased Gas Costs and, in the New York jurisdiction of its Utility segment, earns a return, within certain parameters, on the excess of cumulative funding to the pension plan over the cumulative amount collected in rates.

(2) Included in Other Regulatory Assets on the Consolidated Balance Sheets.

(3) Amounts are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2014 and September 30, 2013 since such amounts are expected to be recovered from ratepayers in the next 12 months.

(4) $9,989 and $13,826 are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2014 and 2013, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $4,853 and $5,608 are included in Other Regulatory Assets on the Consolidated Balance Sheets at September 30, 2014 and 2013, respectively.

(5) Amounts are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2014 and September 30, 2013 since such amounts are expected to be passed back to ratepayers in the next 12 months.

(6) $5,267 and $9,785 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2014 and 2013, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $27,502 and $23,626 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2014 and 2013, respectively.

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

Cost of Removal Regulatory Liability

In the Company’s Utility and Pipeline and Storage segments, costs of removing assets (i.e. asset retirement costs) are collected from customers through depreciation expense. These amounts are not a legal retirement obligation as discussed in Note B — Asset Retirement Obligations. Rather, they are classified as a regulatory

liability in recognition of the fact that the Company has collected dollars from the customer that will be used in the future to fund asset retirement costs.

NYPSC Assessment

On April 7, 2009, the Governor of the State of New York signed into law an amendment to the Public Service Law increasing the allowed utility assessment from the then current rate of one-third of one percent to one percent of a utility's in-state gross operating revenue, together with a temporary surcharge (expiring March 31, 2014) equal, as applied, to an additional one percent of the utility's in-state gross operating revenue. Pursuant to a New York State budget agreement in 2014, the temporary increase in the assessment will be phased out over a three year period ending July 1, 2017. The NYPSC, in a generic proceeding initiated for the purpose of implementing the amended law, has authorized the recovery, through rates, of the full cost of the increased assessment. The assessment is currently being applied to customer bills in the Utility segment's New York jurisdiction.

NYPSC Rate Proceeding

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an "earnings sharing mechanism" ("ESM"). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% would be allocated to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation's pipeline replacement spending by $8.2 million per year. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. The Consolidated Balance Sheet at September 30, 2013 reflected a $7.5 million refund provision related to the settlement agreement. This amount was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014.

Off-System Sales and Capacity Release Credits

The Company, in its Utility segment, has entered into off-system sales and capacity release transactions. Most of the margins on such transactions are returned to the customer with only a small percentage being retained by the Company. The amount owed to the customer has been deferred as a regulatory liability.

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

Note D — Income Taxes

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

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Current Income Taxes —			
Federal	$34,579	$(632)	$(8)
State	12,620	5,503	6,412
Deferred Income Taxes —			
Federal	116,143	130,318	111,176
State	26,272	37,569	32,974
	189,614	172,758	150,554
Deferred Investment Tax Credit	(434)	(426)	(581)
Total Income Taxes	$189,180	$172,332	$149,973
Presented as Follows:			
Other Income	$(434)	$(426)	$(581)
Income Tax Expense	189,614	172,758	150,554
Total Income Taxes	$189,180	$172,332	$149,973

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

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
U.S. Income Before Income Taxes	$488,593	$432,333	$370,050
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$171,008	$151,317	$129,518
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	25,280	27,997	25,601
Miscellaneous	(7,108)	(6,982)	(5,146)
Total Income Taxes	$189,180	$172,332	$149,973

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

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

	At September 30	
	2014	2013
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$1,614,515	$1,504,187
Pension and Other Post-Retirement Benefit Costs	113,248	124,021
Other	87,935	75,419
Total Deferred Tax Liabilities	1,815,698	1,703,627
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(124,452)	(130,256)
Tax Loss and Credit Carryforwards	(171,423)	(215,262)
Other	(103,863)	(90,461)
Total Deferred Tax Assets	(399,738)	(435,979)
Total Net Deferred Income Taxes	$1,415,960	$1,267,648
Presented as Follows:		
Deferred Tax Liability/(Asset) — Current	$(40,323)	$(79,359)
Deferred Tax Liability — Non-Current	1,456,283	1,347,007
Total Net Deferred Income Taxes	$1,415,960	$1,267,648

As a result of certain realization requirements of the authoritative guidance on stock-based compensation, the table of deferred tax liabilities and assets shown above does not include certain deferred tax assets that arose directly from excess tax deductions related to stock-based compensation. Tax benefits of $4.6 million and $0.7 million relating to the excess stock-based compensation deductions were recorded in Paid in Capital during the years ended September 30, 2014 and September 30, 2013, respectively. Cumulative tax benefits of $34.2 million remain as of September 30, 2014 and September 30, 2013 and will be recorded in Paid in Capital in future years when such tax benefits are realized.

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $91.7 million and $85.7 million at September 30, 2014 and 2013, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $163.5 million and $163.4 million at September 30, 2014 and 2013, respectively. Included in the above are regulatory liabilities and assets relating to the tax accounting method change noted below. The amounts are as follows: regulatory liabilities of $52.6 million as of September 30, 2014 and 2013 and regulatory assets of $85.3 million and $82.5 million as of September 30, 2014 and 2013, respectively.

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

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
Balance at Beginning of Year	$2,001	$11,170	$7,766
Additions for Tax Positions Related to Current Year	—	700	1,600
Additions for Tax Positions of Prior Years	2,447	164	2,751
Reductions for Tax Positions of Prior Years	(1,301)	(10,033)	(947)
Balance at End of Year	$3,147	$2,001	$11,170

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

As a result of certain examinations in progress (discussed below), the Company anticipates the balance of unrecognized tax benefits could be reduced during the next 12 months. As of September 30, 2014, the entire balance of unrecognized tax benefits would favorably impact the effective tax rate, if recognized.

The IRS is currently conducting examinations of the Company for fiscal 2014 and fiscal 2013 in accordance with the Compliance Assurance Process ("CAP"). The CAP audit employs a real time review of the Company's books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. The federal statute of limitations remains open for fiscal 2009 and later years. During fiscal 2009, consent was received from the IRS National Office approving the Company's application to change its tax method of accounting for certain capitalized costs relating to its utility property. During the year ended September 30, 2013, local IRS examiners issued no-change reports for fiscal 2009, fiscal 2010 and fiscal 2011. During the year ended September 30, 2014, local IRS examiners issued a no-change report for fiscal 2012. The IRS has reserved the right to re-examine these years, pending the anticipated issuance of IRS guidance addressing the issue for natural gas utilities.

The Company is also subject to various routine state income tax examinations. The Company's principal subsidiaries operate mainly in four states which have statutes of limitations that generally expire between three to four years from the date of filing of the income tax return.

As of September 30, 2014, the Company has a federal net operating loss (NOL) carryover of $367 million, which expires in varying amounts between 2023 and 2033, and minimum tax credit carryforwards of $36 million, that have no expiration date. Approximately $10 million of the NOL carryforward is subject to certain annual limitations, and $87 million is attributable to excess tax deductions related to stock-based compensation as discussed above. In addition, the Company has state NOL carryovers in Pennsylvania, California and New York of $297 million, $183 million and $103 million, respectively, which begin to expire in varying amounts between 2025 and 2033.

On March 31, 2014, the New York State fiscal year 2014-2015 Executive Budget legislation was signed into law. This legislation included numerous tax provisions, including a reduction of the corporate tax rate from 7.1% to 6.5%, effective for tax years beginning after January 1, 2016. This provision resulted in a tax benefit of approximately $2.8 million, which is reflected in the accompanying financial statements.

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Note E — Capitalization and Short-Term Borrowings
Summary of Changes in Common Stock Equity

	Common Stock		Paid In Capital	Earnings Reinvested in the Business		Accumulated Other Comprehensive Income (Loss)
	Shares	Amount				
	(Thousands, except per share amounts)					
Balance at September 30, 2011	82,813	$82,813	$650,749	$1,206,022		$(47,699)
Net Income Available for Common Stock				220,077		
Dividends Declared on Common Stock ($1.44 Per Share)				(119,815)		
Other Comprehensive Loss, Net of Tax						(51,321)
Share-Based Payment Expense(2)			7,156			
Common Stock Issued Under Stock and Benefit Plans(1)	517	517	11,596			
Balance at September 30, 2012	83,330	83,330	669,501	1,306,284		(99,020)
Net Income Available for Common Stock				260,001		
Dividends Declared on Common Stock ($1.48 Per Share)				(123,668)		
Other Comprehensive Income, Net of Tax						79,786
Share-Based Payment Expense(2)			11,537			
Common Stock Issued Under Stock and Benefit Plans(1)	332	332	6,646			
Balance at September 30, 2013	83,662	83,662	687,684	1,442,617		(19,234)
Net Income Available for Common Stock				299,413		
Dividends Declared on Common Stock ($1.52 Per Share)				(127,669)		
Other Comprehensive Income, Net of Tax						15,255
Share-Based Payment Expense(2)			10,654			
Common Stock Issued Under Stock and Benefit Plans(1)	495	495	17,806			
Balance at September 30, 2014	84,157	$84,157	$716,144	$1,614,361	(3)	$(3,979)

(1) Paid in Capital includes tax benefits of $4.6 million, $0.7 million and $1.0 million for September 30, 2014, 2013 and 2012, respectively, related to stock-based compensation.

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

(3) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2014, $1.5 billion of accumulated earnings was free of such limitations.

Common Stock

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment

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Plan allows shareholders to reinvest cash dividends and make cash investments in the Company's common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, at the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent. During 2014, the Company issued 93,731 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 69,729 original issue shares of common stock for the Company's 401(k) plans.

During 2014, the Company issued 433,602 original issue shares of common stock as a result of stock option and SARs exercises and 12,432 original issue shares of common stock for restricted stock units that vested. Holders of stock options, SARs, restricted share awards or restricted stock units will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During 2014, 126,321 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. There were also 3,334 restricted stock award shares forfeited during 2014.

The Company also has a director stock program under which it issues shares of Company common stock to the non-employee directors of the Company who receive compensation under the Company's 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors' services during the fiscal year. Under this program, the Company issued 15,412 original issue shares of common stock during 2014.

Shareholder Rights Plan

In 1996, the Company's Board of Directors adopted a shareholder rights plan (Plan). The Plan has been amended several times since it was adopted and is now embodied in an Amended and Restated Rights Agreement effective December 4, 2008, a copy of which was included as an exhibit to the Form 8-K filed by the Company on December 4, 2008.

Pursuant to the Plan, the holders of the Company's common stock have one right (Right) for each of their shares. Each Right is initially evidenced by the Company's common stock certificates representing the outstanding shares of common stock.

The Rights have anti-takeover effects because they will cause substantial dilution of the Company's common stock if a person (an Acquiring Person) attempts to acquire the Company on terms not approved by the Board of Directors.

The Rights become exercisable upon the occurrence of a Distribution Date as described below, but after a Distribution Date Rights that are owned by an Acquiring Person will be null and void. At any time following a Distribution Date, each holder of a Right may exercise its right to receive, upon payment of an amount calculated under the Rights Agreement, common stock of the Company (or, under certain circumstances, other securities or assets of the Company) having a value equal to two times the amount paid to exercise the Right. However, the Rights are subject to redemption or exchange by the Company prior to their exercise as described below.

A Distribution Date would occur upon the earlier of (i) ten days after the public announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of the Company's common stock or other voting stock (including Synthetic Long Positions as defined in the Plan) having 10% or more of the total voting power of the Company's common stock and other voting stock and (ii) ten days after the commencement or announcement by a person or group of an intention to make a tender or exchange offer that would result in that person acquiring, or obtaining the right to acquire, beneficial ownership of the Company's common stock or other voting stock having 10% or more of the total voting power of the Company's common stock and other voting stock.

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In certain situations after a person or group has acquired beneficial ownership of 10% or more of the total voting power of the Company's stock as described above, each holder of a Right will have the right to exercise its Rights to receive, upon exercise of the right, common stock of the acquiring company having a value equal to two times the amount paid to exercise the right. These situations would arise if the Company is acquired in a merger or other business combination or if 50% or more of the Company's assets or earning power are sold or transferred.

At any time prior to the end of the business day on the tenth day following the Distribution Date, the Company may redeem the Rights in whole, but not in part, at a price of $0.005 per Right, payable in cash or stock. A decision to redeem the Rights requires the vote of 75% of the Company's full Board of Directors. Also, at any time following the Distribution Date, 75% of the Company's full Board of Directors may vote to exchange the Rights, in whole or in part, at an exchange rate of one share of common stock, or other property deemed to have the same value, per Right, subject to certain adjustments.

Upon exercise of the Rights, the Company may need additional regulatory approvals to satisfy the requirements of the Rights Agreement. The Rights will expire on July 31, 2018, unless earlier than that date, they are exchanged or redeemed or the Plan is amended to extend the expiration date.

Stock Option and Stock Award Plans

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

Stock-based compensation expense for the years ended September 30, 2014, 2013 and 2012 was approximately $10.5 million, $11.5 million, and $7.2 million, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statements of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2014, 2013 and 2012 was approximately $4.3 million, $4.6 million and $2.9 million, respectively. A portion of stock-based compensation expense is subject to capitalization under IRS uniform capitalization rules. Stock-based compensation of $0.1 million and less than $0.1 million was capitalized under these rules during the years ended September 30, 2014 and 2013, respectively. Nothing was capitalized during the year ended September 30, 2012.

The Company realized excess tax benefits related to stock-based compensation of $3.1 million, $3.6 million, and $14.2 million for the fiscal years ended September 30, 2014, 2013 and 2012, respectively. The Company recorded tax benefits of $4.6 million, $0.7 million, and $1.0 million in the fiscal years ended September 30, 2014, 2013 and 2012, respectively, due to tax loss carryforwards.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

Stock Options
Transactions involving option shares for all plans are summarized as follows:

	Number of Shares Subject to Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2013	803,500	$34.71		
Granted in 2014	—	$—		
Exercised in 2014	(321,500)	$31.71		
Forfeited in 2014	—	$—		
Outstanding at September 30, 2014	482,000	$36.71	1.80	$16,039
Option shares exercisable at September 30, 2014	482,000	$36.71	1.80	$16,039
Option shares available for future grant at September 30, 2014(1)	712,232			

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

The total intrinsic value of stock options exercised during the years ended September 30, 2014, 2013 and 2012 totaled approximately $13.7 million, $11.6 million, and $13.5 million, respectively. For 2014, 2013 and 2012, the amount of cash received by the Company from the exercise of such stock options was approximately $7.4 million, $2.6 million, and $7.6 million, respectively. The Company last granted stock options in fiscal 2007 and all outstanding stock options have been fully vested since fiscal 2010.

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

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2013	2,002,704	$46.73		
Granted in 2014	—	$—		
Exercised in 2014	(209,222)	$34.90		
Forfeited in 2014	—	$—		
Canceled in 2014	—	$—		
Outstanding at September 30, 2014	1,793,482	$48.11	5.93	$39,246
SARs exercisable at September 30, 2014	1,434,023	$46.65	5.45	$33,466

The Company granted 412,970 and 166,000 SARs during the years ended September 30, 2013 and 2012, respectively. The weighted average grant date fair value of SARs granted in 2013 and 2012 was $10.66 per share and $11.20 per share, respectively. The SARs granted in 2013 may be settled in cash, in shares of common stock of the Company, or in a combination of cash and shares of common stock of the Company, as determined by the Company. The SARs

granted in 2012 will be settled in shares of common stock of the Company. The Company's

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SARs include both performance based and non-performance based SARs, but the performance conditions associated with the performance based SARs at the time of grant have all been subsequently met. The SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for SARs is the same as the accounting for stock options. The SARs granted during the year ended September 30, 2013 vest and become exercisable annually in one-third increments. The SARs granted during the year ended September 30, 2012 vest annually in one-third increments and become exercisable on the third anniversary of the date of grant. The weighted average grant date fair value of the SARs granted during the years ended September 30, 2013 and 2012 was estimated on the date of grant using the same accounting treatment that is applied for stock options.
The total intrinsic value of SARs exercised during the years ended September 30, 2014, 2013 and 2012 totaled approximately $8.4 million, $0.8 million, and less than $0.1 million, respectively. For the years ended September 30, 2014, 2013 and 2012, 323,188 SARs, 287,168 SARs and 435,169 SARs, respectively, became fully vested. The total fair value of the SARs that became vested during each of the years ended September 30, 2014, 2013 and 2012 was approximately $3.8 million, $3.6 million and $3.8 million, respectively. As of September 30, 2014, unrecognized compensation expense related to SARs totaled approximately $0.5 million, which will be recognized over a weighted average period of 8 months.

The fair value of SARs at the date of grant was estimated using the Black-Scholes-Merton closed form model. The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the SARs. The expected life is based on historical experience and the expected volatility is based on historical daily stock price returns. For SARs grants during the years ended September 30, 2013 and 2012, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees. The following weighted average assumptions were used in estimating the fair value of SARs at the date of grant:

	Year Ended September 30				
	2014	2013		2012	
Risk-Free Interest Rate	N/A	1.55	%	1.59	%
Expected Life (Years)	N/A	8.25		8.25	
Expected Volatility	N/A	25.61	%	24.97	%
Expected Dividend Yield (Quarterly)	N/A	0.69	%	0.64	%

Restricted Share Awards
Transactions involving restricted share awards for all plans are summarized as follows:

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Outstanding at September 30, 2013	127,453	$51.69
Granted in 2014	—	$—
Vested in 2014	(34,601)	$58.17
Forfeited in 2014	(3,334)	$55.09
Outstanding at September 30, 2014	89,518	$49.05

The Company did not grant any restricted share awards (non-vested stock as defined by the current accounting literature) during the year ended September 30, 2013. The Company granted 41,525 restricted share awards during the year ended September 30, 2012 with a weighted average grant date fair value of $55.09 per share. As of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

September 30, 2014, unrecognized compensation expense related to restricted share awards totaled approximately $1.3 million, which will be recognized over a weighted average period of 2.7 years.

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2014 will lapse as follows: 2015 — 29,518 shares; 2016 — 5,000 shares; 2018 — 35,000 shares; and 2021 — 20,000 shares.

Restricted Stock Units

Transactions involving non-performance based restricted stock units for all plans are summarized as follows:

	Number of Restricted Stock Units	Weighted Average Fair Value per Award
Outstanding at September 30, 2013	143,500	$51.53
Granted in 2014	82,151	$65.24
Vested in 2014	(12,432)	$60.54
Forfeited in 2014	(8,700)	$54.53
Outstanding at September 30, 2014	204,519	$56.36

The Company also granted 44,200 and 68,450 non-performance based restricted stock units during the years ended September 30, 2013 and 2012, respectively. The weighted average fair value of such non-performance based restricted stock units granted in 2013 and 2012 was $51.11 per share and $47.10 per share, respectively. As of September 30, 2014, unrecognized compensation expense related to non-performance based restricted stock units totaled approximately $5.4 million, which will be recognized over a weighted average period of 1.7 years.

Vesting restrictions for the non-performance based restricted stock units outstanding at September 30, 2014 will lapse as follows: 2015 — 49,340 units; 2016 — 61,534 units; 2017 — 59,893 units; 2018 — 22,967 units; and 2019 - 10,785 units.

Transactions involving performance based restricted stock units for all plans are summarized as follows:

	Number of Performance Based Restricted Stock Units	Weighted Average Fair Value per Award
Outstanding at September 30, 2013	255,604	$49.51
Granted in 2014	—	$—
Vested in 2014	—	$—
Forfeited in 2014	(21,728)	$48.49
Outstanding at September 30, 2014	233,876	$49.61

The Company granted 255,604 performance based restricted stock units during the year ended September 30, 2013 with a weighted average grant date fair value of $49.51 per share. The Company did not grant any performance based restricted stock units during the year ended September 30, 2012. The performance based restricted stock units granted during the year ended September 30, 2013 must meet a performance condition over the performance cycle of October 1, 2012 to September 30, 2015. The performance condition over the performance cycle, generally stated, is the Company’s total return on capital as compared to the same metric for companies in the Natural Gas Distribution and Integrated Natural Gas Companies group as calculated and reported in the Monthly Utility Reports of AUS, Inc., a leading industry consultant. The number of performance based restricted stock units that will vest will depend upon the Company’s performance relative to the report group and not upon the absolute level of return achieved by the Company. As of September 30, 2014, unrecognized compensation expense related to performance based restricted stock units totaled approximately $3.1 million, which will be recognized over a weighted average

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period of 1 year. Vesting restrictions will lapse during fiscal 2016 for the 233,876 performance based restricted stock units outstanding at September 30, 2014.

Performance Shares

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

	Number of Performance Shares	Weighted Average Fair Value per Award
Outstanding at September 30, 2013	—	$—
Granted in 2014	116,090	$67.16
Vested in 2014	—	$—
Forfeited in 2014	(17,624)	$67.16
Outstanding at September 30, 2014	98,466	$67.16

The Company did not grant any performance shares during the years ended September 30, 2013 and 2012. As of September 30, 2014, unrecognized compensation expense related to performance shares totaled approximately $4.6 million, which will be recognized over a weighted average period of 1.5 years. Vesting restrictions will lapse during fiscal 2017 for the 98,466 performance shares outstanding at September 30, 2014.

Half of the performance shares granted during the year ended September 30, 2014 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2013 to September 30, 2016. The performance goal over the performance cycle is the Company's total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee ("Report Group"). Total return on capital for a given company means the average of the Report Group companies' returns on capital for each twelve month period corresponding to each of the Company's fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these performance shares that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value of these performance shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award.

The other half of the performance shares granted during the year ended September 30, 2014 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2013 to September 30, 2016. The performance goal over the performance cycle is the Company's three-year total shareholder return relative to the three-year total shareholder return of the other companies in the Report Group. Three-year total shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company's securities at each ex-dividend date) in the Bloomberg database. The number of these total shareholder return performance shares ("TSR performance shares") that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value price at the date of grant for the TSR performance shares is determined using a Monte Carlo simulation technique, which includes a reduction in value for the present value of forgone dividends over the vesting term of the award. This price is multiplied by the number of TSR performance shares awarded, the result of which is recorded as compensation expense over the vesting term of the award. In calculating fair value of the award, the risk-free interest rate is based on the yield of a Treasury Note with a term commensurate with the remaining term of the TSR performance shares. The remaining term is based on the remainder of the performance cycle as of the date of grant. The expected volatility is based on historical daily stock price returns. For the TSR performance shares, it

was assumed that there would

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be no forfeitures, based on the vesting term and the number of grantees. The following assumptions were used in estimating the fair value of the TSR performance shares at the date of grant:

	Year Ended September 30		
	2014	2013	2012
Risk-Free Interest Rate	0.62 %	N/A	N/A
Remaining Term at Date of Grant (Years)	2.78	N/A	N/A
Expected Volatility	28.3 %	N/A	N/A
Expected Dividend Yield (Quarterly)	N/A	N/A	N/A

Redeemable Preferred Stock
As of September 30, 2014, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.
Long-Term Debt
The outstanding long-term debt is as follows:

	At September 30	
	2014	2013
	(Thousands)	
Medium-Term Notes(1):		
7.4% due March 2023 to June 2025	$99,000	$99,000
Notes(1)(3):		
3.75% to 8.75% due April 2018 to March 2023	1,550,000	1,550,000
Total Long-Term Debt	1,649,000	1,649,000
Less Current Portion(2)	—	—
	$1,649,000	$1,649,000

(1) The Medium-Term Notes and Notes are unsecured.
(2) None of the Company's long-term debt at September 30, 2014 and 2013 will mature within the following twelve-month period.
(3) The holders of these notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade.

On February 15, 2013, the Company issued $500 million of 3.75% notes due March 1, 2023. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $495.4 million. The proceeds of this debt issuance were used to refund the $250.0 million of 5.25% notes that matured in March 2013, as well as for general corporate purposes, including the reduction of short-term debt.
As of September 30, 2014, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: zero for 2015 through 2017, $300.0 million in 2018, $250.0 million in 2019 and $1,099.0 million thereafter.

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Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. The Company maintains a $750.0 million syndicated committed credit facility, which commitment extends through January 6, 2017. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines.

The total amount available to be issued under the Company's commercial paper program is $300.0 million. At September 30, 2014, the commercial paper program was backed by the $750.0 million syndicated committed credit facility.

At September 30, 2014, the Company had outstanding commercial paper of $85.6 million. The Company did not have any outstanding notes payable to banks at September 30, 2014. At September 30, 2014, the weighted average interest rate on the commercial paper was 0.31% . The Company had no outstanding commercial paper and short-term notes payable to banks at September 30, 2013.

Debt Restrictions

Under the committed credit facility, the Company agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through January 6, 2017. At September 30, 2014, the Company's debt to capitalization ratio (as calculated under the facility) was .42. The constraints specified in the committed credit facility would have permitted an additional $2.74 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

If a downgrade in any of the Company's credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

The Company's $750.0 million committed credit facility 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 committed credit facility. 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, 2014, the Company had no debt outstanding under the committed credit facility.

Under the Company's existing indenture covenants, at September 30, 2014, the Company would have been permitted to issue up to a maximum of $1.92 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company's present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company's ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt.

The Company's 1974 indenture pursuant to which $99.0 million (or 6.0%) of the Company's long-term debt (as of September 30, 2014) was issued, contains a cross-default provision whereby the failure by the Company to

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

Note F — Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of September 30, 2014 and 2013. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over the counter swaps has been changed to combine gas and oil swaps at both September 30, 2014 and September 30, 2013. In the September 30, 2013 Form 10-K, gas swaps were reported separately from oil swaps. This change in presentation was made because a significant number of the counterparties enter into both gas and oil swap agreements with the Company.

	At Fair Value as of September 30, 2014				
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Fund	$23,794	$—	$—	$—	$23,794
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	2,725	—	—	(1,987)	738
Over the Counter Swaps — Gas and Oil	—	75,951	1,368	(5,451)	71,868
Other Investments:					
Balanced Equity Mutual Fund	35,331	—	—	—	35,331
Common Stock — Financial Services Industry	6,629	—	—	—	6,629
Other Common Stock	455	—	—	—	455
Hedging Collateral Deposits	2,734	—	—	—	2,734
Total	$71,668	$75,951	$1,368	$(7,438)	$141,549
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	$2,674	$—	$—	$(1,987)	$687
Over the Counter Swaps — Gas and Oil	—	5,523	—	(5,451)	72
Total	$2,674	$5,523	$—	$(7,438)	$759
Total Net Assets/(Liabilities)	$68,994	$70,428	$1,368	$—	$140,790

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

	At Fair Value as of September 30, 2013				
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$51,332	$—	$—	$—	$51,332
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	2,552	—	—	(1,641)	911
Over the Counter Swaps — Gas and Oil	—	57,070	—	(9,003)	48,067
Other Investments:					
Balanced Equity Mutual Fund	31,813	—	—	—	31,813
Common Stock — Financial Services Industry	6,544	—	—	—	6,544
Other Common Stock	330	—	—	—	330
Hedging Collateral Deposits	1,094	—	—	—	1,094
Total	$93,665	$57,070	$—	$(10,644)	$140,091
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	$1,641	$—	$—	$(1,641)	$—
Over the Counter Swaps — Gas and Oil	—	4,452	5,190	(9,003)	639
Total	$1,641	$4,452	$5,190	$(10,644)	$639
Total Net Assets/(Liabilities)	$92,024	$52,618	$(5,190)	$—	$139,452

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

Derivative Financial Instruments

At September 30, 2014 and 2013, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX and ICE futures contracts used in the Company's Energy Marketing segment. Hedging collateral deposits of $2.7 million (at September 30, 2014) and $1.1 million (at September 30, 2013), which are associated with these futures contracts, have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at September 30, 2014 and 2013 consist of natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments and the majority of the crude oil price swap agreements used in the Company's Exploration and Production segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The derivative financial instruments reported in Level 3 consist of a portion of the crude oil price swap agreements used in the Company's Exploration and Production segment at September 30, 2014 and 2013. The fair value of the Level 3 crude oil price swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume).

The significant unobservable input used in the fair value measurement of a portion of the Company's over-the-counter crude oil swaps is the basis differential between Midway Sunset oil and NYMEX contracts. Significant changes in the assumed basis differential could result in a significant change in the value of the derivative financial instruments. At September 30, 2014, it was assumed that Midway Sunset oil was 98.2% of NYMEX. This is based on a historical twelve month average of Midway Sunset oil sales verses NYMEX settlements. During this twelve-month period, the

price of Midway Sunset oil ranged from 95.3% to 100.6% of NYMEX. If the price of Midway Sunset oil relative to NYMEX used in the fair value measurement calculation had been 10 percentage points higher,

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

the fair value of the Level 3 crude oil price swap agreements asset would have changed from a net asset of $1.4 million to a net liability of $1.2 million at September 30, 2014. If the price of Midway Sunset oil relative to NYMEX used in the fair value measurement had been 10 percentage points lower, the fair value measurement of the Level 3 crude oil price swap agreements asset would have been approximately $2.6 million higher at September 30, 2014. These calculated amounts are based solely on basis differential changes and do not take into account any other changes to the fair value measurement calculation.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2014, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company's (for a liability) credit default swaps rates.

The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the years ended September 30, 2014 and September 30, 2013, respectively. For the years ended September 30, 2014 and September 30, 2013, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the periods presented in the tables below. All settlements of the derivative financial instruments are reflected in the Gains/Losses Realized and Included in Earnings column of the tables below (amounts in parentheses indicate credits in the derivative asset/liability accounts).

Fair Value Measurements Using Unobservable Inputs (Level 3)

	October 1, 2013	Total Gains/Losses (Gains)/Losses Realized and Included in Earnings		Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2014
	(Dollars in thousands)					
Derivative Financial Instruments(2)	$(5,190)	$2,217	(1)	$4,341	$—	$1,368

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2014.

(2) Derivative Financial Instruments are shown on a net basis.

	October 1, 2012	Total Gains/Losses (Gains)/Losses Realized and Included in Earnings		Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2013
	(Dollars in thousands)					
Derivative Financial Instruments(2)	$(19,664)	$13,408	(1)	$1,066	$—	$(5,190)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2013.

(2) Derivative Financial Instruments are shown on a net basis.

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

Note G — Financial Instruments

Long-Term Debt

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

	At September 30			
	2014 Carrying Amount	2014 Fair Value	2013 Carrying Amount	2013 Fair Value
	(Thousands)			
Long-Term Debt	$1,649,000	$1,775,715	$1,649,000	$1,767,519

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

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

Other Investments

Investments in life insurance are stated at their cash surrender values or net present value as discussed below. Investments in an equity mutual fund and the stock of an insurance company (marketable equity securities), as discussed below, are stated at fair value based on quoted market prices.

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance contracts amounted to $44.4 million and $57.6 million at September 30, 2014 and 2013, respectively. The fair value of the equity mutual fund was $35.3 million and $31.8 million at September 30, 2014 and 2013, respectively. The gross unrealized gain on this equity mutual fund was $8.4 million at September 30, 2014 and $5.7 million at September 30, 2013. The fair value of the stock of an insurance company was $6.6 million and $6.5 million at September 30, 2014 and 2013, respectively. The gross unrealized gain on this stock was $4.5 million and $4.1 million at September 30, 2014 and 2013, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment as well as the Energy Marketing segment. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. These instruments are accounted for as cash flow hedges. The Company also enters into futures contracts and swaps, which are accounted for as cash flow hedges, to manage the price risk associated with forecasted gas purchases. The Company enters into futures contracts and swaps to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in value of natural gas held in storage. These instruments are accounted for as fair value hedges. The duration of the Company's combined cash

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

flow and fair value hedges does not typically exceed 5 years. The Exploration and Production segment holds the majority of the Company's derivative financial instruments. The derivative financial instruments held by the Energy Marketing segment are not considered to be material to the Company.

The Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at September 30, 2014 and September 30, 2013. All of the derivative financial instruments reported on those line items relate to commodity contracts.

Cash Flow Hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of September 30, 2014, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	212.1	Bcf (short positions)
Natural Gas	3.3	Bcf (long positions)
Crude Oil	3,285,000	Bbls (short positions)

At March 31, 2014, the Company de-designated a portion of its crude oil swaps as cash flow hedges and simultaneously re-designated them as cash flow hedges using a revised effectiveness testing model. Amounts in accumulated other comprehensive loss at March 31, 2014 associated with the de-designated crude oil swaps will be amortized into the income statement as the anticipated hedged production occurs. Since the de-designated crude oil swaps were re-designated as cash flow hedges at March 31, 2014, future gains or losses on such derivatives, to the extent they are effective, will be reported as a component of other comprehensive income (loss) and reclassified into earnings in the period or periods during which the hedged transaction affects earnings. The net mark-to-market impact recorded in earnings related to all of the Company's crude oil swaps, including ineffectiveness and economic hedges, was a loss of $0.1 million and $3.7 million for the years ended September 30, 2014 and September 30, 2013, respectively.

As of September 30, 2014, the Company had $76.1 million ($43.7 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $41.1 million ($23.6 million after tax) of such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur. It is expected that $35.0 million ($20.1 million after tax) of unrealized gains will be reclassified into the Consolidated Statement of Income after 12 months as the expected sales of the underlying commodities occur.

Refer to Note A, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain (loss) pertaining to derivative financial instruments.

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

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2014 and 2013 (Dollar Amounts in Thousands)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Year Ended September 30,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Year Ended September 30,		Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Year Ended September 30,	
	2014	2013		2014	2013		2014	2013
Commodity Contracts	$9,763	$87,813	Operating Revenue	$(14,880)	$36,949	Operating Revenue	$ 624	$ (2,045)
Commodity Contracts	$(4,429)	$3,977	Purchased Gas	$(2,767)	$(920)	Not Applicable	$ —	$ —
Total	$5,334	$91,790		$(17,647)	$36,029		$ 624	$ (2,045)

Fair Value Hedges

The Company utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in the value of certain natural gas held in storage. With respect to fixed price sales commitments, the Company enters into long positions to mitigate the risk of price increases for natural gas supplies that could occur after the Company enters into fixed price sales agreements with its customers. With respect to fixed price purchase commitments, the Company enters into short positions to mitigate the risk of price decreases that could occur after the Company locks into fixed price purchase deals with its suppliers. With respect to storage hedges, the Company enters into short positions to mitigate the risk of price decreases that could result in a lower of cost or market writedown of the value of natural gas in storage that is recorded in the Company's financial statements. As of September 30, 2014, the Company's Energy Marketing segment had fair value hedges covering approximately 16.1 Bcf (15.8 Bcf of fixed price sales commitments, 0.2 Bcf of fixed price purchase commitments and 0.1 Bcf of commitments related to the withdrawal of storage gas). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

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

		September 30, 2014	September 30, 2014
		(In thousands)	
Commodity Contracts	Operating Revenues	$696	$(696)
Commodity Contracts	Purchased Gas	(574)	574
		$122	$(122)

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

Credit Risk

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with sixteen counterparties of which fourteen are in a net gain position. On average, the Company had $5.1 million of credit exposure per counterparty in a gain position at September 30, 2014. The maximum credit exposure per counterparty in a gain position at September 30, 2014 was $18.7 million. As of September 30, 2014, no collateral was received from the counterparties by the Company. The Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties' credit ratings declined to levels at which the counterparties were required to post collateral.

As of September 30, 2014, eleven of the sixteen counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company's outstanding derivative instrument contracts were in a liability position (or if the liability were larger) and/or the Company's credit rating declined, then additional hedging collateral deposits may be required. At September 30, 2014, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $60.1 million according to the Company's internal model (discussed in Note F — Fair Value Measurements). At September 30, 2014, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $0.1 million according to the Company's internal model (discussed in Note F — Fair Value Measurements). For its over-the-counter swap agreements, no hedging collateral deposits were required to be posted by the Company at September 30, 2014.

For its exchange traded futures contracts, the Company was required to post $2.7 million in hedging collateral deposits as of September 30, 2014. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company's requirement to post hedging collateral deposits is based on the fair value determined by the Company's counterparties, which may differ from the Company's assessment of fair value. Hedging collateral deposits may also include closed derivative positions in which the broker has not cleared the cash from the account to offset the derivative liability. The Company records liabilities related to closed derivative positions in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. These liabilities are relieved when the broker clears the cash from the hedging collateral deposit account. This is discussed in Note A under Hedging Collateral Deposits.

Note H — Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan). The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Certain non-collectively bargained employees hired after June 30, 2003 and certain collectively bargained employees hired after October 31, 2003 are eligible for a Retirement Savings Account benefit provided under the Company's defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account were $1.9 million, $1.2 million and $0.9 million for the years ended September 30, 2014, 2013 and 2012, respectively. Costs associated with the Company's

contributions to the Tax-Deferred Savings Plans, exclusive of the costs associated with the Retirement Savings Account, were $5.2 million, $4.4 million, and $4.3 million for the years ended September 30, 2014, 2013 and 2012, respectively.

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

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

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

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and other post-retirement benefits are shown in the tables below. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is September 30 for fiscal years 2014, 2013 and 2012.

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

	Retirement Plan Year Ended September 30			Other Post-Retirement Benefits Year Ended September 30		
	2014	2013	2012	2014	2013	2012
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$946,305	$1,070,744	$949,777	$460,634	$561,263	$485,452
Service Cost	11,987	15,846	14,202	2,939	4,705	4,016
Interest Cost	43,574	36,498	41,526	21,308	19,212	21,315
Plan Participants' Contributions	—	—	—	2,265	2,141	1,956
Retiree Drug Subsidy Receipts	—	—	—	1,419	1,526	1,528
Actuarial (Gain) Loss	53,887	(121,631)	120,338	1,087	(104,455)	71,708
Benefits Paid	(56,254)	(55,152)	(55,099)	(24,069)	(23,758)	(24,712)
Benefit Obligation at End of Period	$999,499	$946,305	$1,070,744	$465,583	$460,634	$561,263
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$799,307	$701,676	$601,719	$472,392	$414,134	$351,990
Actual Return on Plan Assets	93,238	98,783	111,034	44,898	61,715	63,552
Employer Contributions	33,500	54,000	44,022	2,115	18,160	21,348
Plan Participants' Contributions	—	—	—	2,265	2,141	1,956
Benefits Paid	(56,254)	(55,152)	(55,099)	(24,069)	(23,758)	(24,712)
Fair Value of Assets at End of Period	$869,791	$799,307	$701,676	$497,601	$472,392	$414,134
Net Amount Recognized at End of Period (Funded Status)	$(129,708)	$(146,998)	$(369,068)	$32,018	$11,758	$(147,129)
Amounts Recognized in the Balance Sheets Consist of:						
Non-Current Liabilities	$(129,708)	$(146,998)	$(369,068)	$(4,494)	$(11,016)	$(147,129)
Non-Current Assets	—	—	—	36,512	22,774	—
Net Amount Recognized at End of Period	$(129,708)	$(146,998)	$(369,068)	$32,018	$11,758	$(147,129)
Accumulated Benefit Obligation	$940,068	$886,942	$986,223	N/A	N/A	N/A
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	4.25%	4.75%	3.50%	4.25%	4.75%	3.50%
	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%

Rate of Compensation
Increase

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

	Retirement Plan Year Ended September 30			Other Post-Retirement Benefits Year Ended September 30		
	2014	2013	2012	2014	2013	2012
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	$11,987	$15,846	$14,202	$2,939	$4,705	$4,016
Interest Cost	43,574	36,498	41,526	21,308	19,212	21,315
Expected Return on Plan Assets	(59,974)	(57,346)	(59,701)	(37,424)	(32,872)	(28,971)
Amortization of Prior Service Cost (Credit)	210	238	269	(2,138)	(2,138)	(2,138)
Amortization of Transition Amount	—	—	—	—	8	10
Recognition of Actuarial Loss(1)	36,007	52,776	39,615	2,645	20,892	24,057
Net Amortization and Deferral for Regulatory Purposes	8,151	(10,406)	(6,900)	23,263	11,844	6,162
Net Periodic Benefit Cost	$39,955	$37,606	$29,011	$10,593	$21,651	$24,451
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	4.75%	3.50%	4.50%	4.75%	3.50%	4.50%
Expected Return on Plan Assets	8.00%	8.00%	8.25%	8.00%	8.00%	8.25%
Rate of Compensation Increase	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%

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

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

In addition to the Retirement Plan discussed above, the Company also has Non-Qualified benefit plans that cover a group of management employees designated by the Chief Executive Officer of the Company. These plans provide for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit cost associated with these plans were $7.5 million, $9.6 million and $9.1 million in 2014, 2013 and 2012, respectively. The accumulated benefit obligations for the plans were $65.7

million, $57.2 million and $54.5 million at September 30, 2014, 2013 and 2012, respectively. The projected benefit obligations for the plans were $85.5 million, $77.1 million and $88.5 million at September 30, 2014, 2013 and 2012, respectively. At September 30, 2014, $6.6 million of the projected benefit obligation is recorded in Other Accruals and Current Liabilities and the remaining $78.9 million is recorded in Other Deferred Credits on the Consolidated Balance Sheets. At September 30, 2013 and 2012, the projected benefit obligations are recorded in Other Deferred Credits on the Consolidated Balance Sheets. The weighted average discount rates for these plans were 3.50%, 3.75% and 2.50% as of September 30, 2014, 2013 and 2012, respectively and a weighted

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

average rate of compensation increase of 7.50%, 7.75% and 7.75% as of September 30, 2014, 2013 and 2012, respectively.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2014, the changes in such amounts during 2014, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2015 are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits	Non-Qualified Benefit Plans
	(Thousands)		
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Loss	$(226,897)	$(32,082)	$(23,532)
Prior Service (Cost) Credit	(856)	6,940	—
Net Amount Recognized	$(227,753)	$(25,142)	$(23,532)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2014(1)			
Decrease (Increase) in Actuarial Loss, excluding amortization(2)	$(20,622)	$6,387	$(5,424)
Change due to Amortization of Actuarial Loss	36,007	2,645	3,008
Prior Service (Cost) Credit	210	(2,138)	—
Net Change	$15,595	$6,894	$(2,416)
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Loss	$(36,129)	$(4,148)	$(2,925)
Prior Service (Cost) Credit	(183)	1,913	—
Net Amount Expected to be Recognized	$(36,312)	$(2,235)	$(2,925)

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

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

In order to adjust the funded status of its pension (tax-qualified and non-qualified) and other post-retirement benefit plans at September 30, 2014, the Company recorded a $19.2 million decrease to Other Regulatory Assets in the Company’s Utility and Pipeline and Storage segments and a $0.9 million (pre-tax) decrease to Accumulated Other Comprehensive Loss.

The effect of the discount rate change for the Retirement Plan in 2014 was to increase the projected benefit obligation of the Retirement Plan by $53.7 million. In 2014, other actuarial experience increased the projected benefit obligation for the Retirement Plan by $0.2 million. The effect of the discount rate change for the Retirement Plan in 2013 was to decrease the projected benefit obligation of the Retirement Plan by $147.9 million. The effect of the discount rate change for the Retirement Plan in 2012 was to increase the projected benefit obligation of the Retirement Plan by $118.8 million.

The Company made cash contributions totaling $33.5 million to the Retirement Plan during the year ended September 30, 2014. The Company expects that the annual contribution to the Retirement Plan in 2015 will be in the range of $15.0 million to $25.0 million. Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in 2015 in order

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

to be in compliance with the Pension Protection Act of 2006 (as impacted by the Moving Ahead for Progress in the 21st Century Act). In July 2012, the Surface Transportation Extension Act, which is also referred to as the Moving Ahead for Progress in the 21st Century Act (the Act), was passed by Congress and signed by the President. The Act included pension funding stabilization provisions. The Highway and Transportation Funding Act of 2014 (HAFTA) was passed by Congress on July 2014 and signed by the President in August 2014. HAFTA extended certain funding stabilization provisions of the Act signed into law in 2012. The Company is continually evaluating its future contributions in light of the provisions of these laws.

The following Retirement Plan benefit payments, which reflect expected future service, are expected to be paid by the Retirement Plan during the next five years and the five years thereafter: $59.4 million in 2015; $60.4 million in 2016; $61.3 million in 2017; $62.2 million in 2018; $62.9 million in 2019; and $326.2 million in the five years thereafter.

The effect of the discount rate change in 2014 was to increase the other post-retirement benefit obligation by $26.4 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2014 by $25.3 million primarily attributable to a revision in assumed per-capita claims cost, premiums and participant contributions based on actual experience.

The effect of the discount rate change in 2013 was to decrease the other post-retirement benefit obligation by $75.9 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2013 by $28.6 million as the increase in obligation attributable to the change in mortality assumption was more than offset by the decrease in obligation attributable to a revision in assumed per-capita claims cost, premiums and participant contributions based on actual experience.

The effect of the discount rate change in 2012 was to increase the other post-retirement benefit obligation by $65.6 million. Other actuarial experience increased the other post-retirement benefit obligation in 2012 by $6.1 million.

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

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

	Benefit Payments	Subsidy Receipts
2015	$25,594	$(1,955)
2016	$26,909	$(2,143)
2017	$28,113	$(2,323)
2018	$29,226	$(2,511)
2019	$30,173	$(2,708)
2020 through 2024	$163,470	$(16,104)

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	2014		2013		2012	
Rate of Increase for Pre Age 65 Participants	7.10	%(1)	7.28	%(1)	7.46	%(1)
Rate of Increase for Post Age 65 Participants	6.73	%(1)	6.78	%(1)	6.84	%(1)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	7.47	%(1)	7.78	%(1)	8.08	%(1)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	6.73	%(1)	6.78	%(1)	6.84	%(1)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	6.79	%(1)	7.03	%(1)	7.13	%(1)

(1)It was assumed that this rate would gradually decline to 4.5% by 2028.

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2014 would increase by $53.0 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2014 by $3.3 million. If the health care cost trend rates were decreased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2014 would decrease by $44.6 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2014 by $2.8 million.

The Company made cash contributions totaling $2.0 million to its VEBA trusts and 401(h) accounts during the year ended September 30, 2014. In addition, the Company made direct payments of $0.1 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2014. The Company expects that the annual contribution to its VEBA trusts and 401(h) accounts in 2015 will be in the range of $2.0 million to $5.0 million.

Investment Valuation

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

The inputs or methodologies used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of September 30, 2014 and 2013, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall, based on the lowest level input that is significant to the fair value measurement in its entirety (dollars in thousands):

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Total Fair Value Amounts at September 30, 2014	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(1)	$268,649	$171,979	$96,670	$—
International Equities(2)	80,957	1,969	78,988	—
Global Equities(3)	104,238	—	104,238	—
Domestic Fixed Income(4)	299,494	63,187	236,307	—
International Fixed Income(5)	1,240	508	732	—
Global Fixed Income(6)	93,704	—	93,704	—
Hedge Fund Investments	45,213	—	—	45,213
Real Estate	3,792	—	—	3,792
Cash and Cash Equivalents	33,544	—	33,544	—
Total Retirement Plan Investments	930,831	237,643	644,183	49,005
401(h) Investments	(54,921)	(14,105)	(37,907)	(2,909)
Total Retirement Plan Investments (excluding 401(h) Investments)	$875,910	$223,538	$606,276	$46,096
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(6,119)			
Total Retirement Plan Assets	$869,791			

	Total Fair Value Amounts at September 30, 2013	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(1)	$402,107	$271,071	$131,036	$—
International Equities(2)	103,028	2,355	100,673	—
Global Equities(3)	25,325	—	25,325	—
Domestic Fixed Income(4)	163,750	71,185	92,565	—
International Fixed Income(5)	2,762	1,318	1,444	—
Global Fixed Income(6)	88,084	—	88,084	—
Hedge Fund Investments	42,027	—	—	42,027
Real Estate	2,723	—	—	2,723
Cash and Cash Equivalents	22,694	—	22,694	—
Total Retirement Plan Investments	852,500	345,929	461,821	44,750
401(h) Investments	(49,453)	(20,141)	(26,706)	(2,606)
Total Retirement Plan Investments (excluding 401(h) Investments)	$803,047	$325,788	$435,115	$42,144
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(3,740)			
Total Retirement Plan Assets	$799,307			

(1) Domestic Equities include mostly collective trust funds, common stock, and exchange traded funds.
(2) International Equities include mostly collective trust funds and common stock.

(3) Global Equities are comprised of a collective trust fund.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

(4) Domestic Fixed Income securities include mostly collective trust funds, corporate/government bonds and mortgages, and exchange traded funds.
(5) International Fixed Income securities include mostly collective trust funds and exchange traded funds.
(6) Global Fixed Income securities are comprised of a collective trust fund.

	Total Fair Value Amounts at September 30, 2014	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				
Collective Trust Funds — Domestic Equities	$148,219	$—	$148,219	$—
Collective Trust Funds — International Equities	54,881	—	54,881	—
Exchange Traded Funds — Fixed Income	236,513	236,513	—	—
Cash Held in Collective Trust Funds	6,412	—	6,412	—
Total VEBA Trust Investments	446,025	236,513	209,512	—
401(h) Investments	54,921	14,105	37,907	2,909
Total Investments (including 401(h) Investments)	$500,946	$250,618	$247,419	$2,909
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(3,345)			
Total Other Post-Retirement Benefit Assets	$497,601			

	Total Fair Value Amounts at September 30, 2013	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				
Collective Trust Funds — Domestic Equities	$205,623	$—	$205,623	$—
Collective Trust Funds — International Equities	87,613	—	87,613	—
Exchange Traded Funds — Fixed Income	122,558	122,558	—	—
Real Estate	55	—	—	55
Cash Held in Collective Trust Funds	11,678	—	11,678	—
Total VEBA Trust Investments	427,527	122,558	304,914	55
401(h) Investments	49,453	20,141	26,706	2,606
Total Investments (including 401(h) Investments)	$476,980	$142,699	$331,620	$2,661
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(4,588)			
Total Other Post-Retirement Benefit Assets	$472,392			

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The following tables provide a reconciliation of the beginning and ending balances of the Retirement Plan and other post-retirement benefit assets measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3). Note: For the years ended September 30, 2014 and September 30, 2013, there were no transfers from Level 1 to Level 2. In addition, as shown in the following tables, there were no transfers in or out of Level 3.

	Retirement Plan Level 3 Assets (Thousands)			
	Hedge Funds	Real Estate	Excluding 401(h) Investments	Total
Balance at September 30, 2012	$39,956	$6,170	$(2,680)	$43,446
Realized Gains/(Losses)	—	(73)	4	(69)
Unrealized Gains/(Losses)	2,071	515	(156)	2,430
Purchases	—	188	(11)	177
Sales	—	(4,077)	237	(3,840)
Balance at September 30, 2013	42,027	2,723	(2,606)	42,144
Realized Gains/(Losses)	—	62	(4)	58
Unrealized Gains/(Losses)	3,186	(10)	(239)	2,937
Purchases	—	1,111	(65)	1,046
Sales	—	(94)	5	(89)
Balance at September 30, 2014	$45,213	$3,792	$(2,909)	$46,096

	Other Post-Retirement Benefit Level 3 Assets (Thousands)		
	VEBA Trust Investments Real Estate	Including 401(h) Investments	Other Post-Retirement Benefit Investments
Balance at September 30, 2012	$1,305	$2,680	$3,985
Realized Gains/(Losses)	940	(4)	936
Unrealized Gains/(Losses)	385	156	541
Purchases	—	11	11
Sales	(2,575)	(237)	(2,812)
Balance at September 30, 2013	55	2,606	2,661
Realized Gains/(Losses)	(40)	4	(36)
Unrealized Gains/(Losses)	—	239	239
Purchases	—	65	65
Sales	(15)	(5)	(20)
Balance at September 30, 2014	$—	$2,909	$2,909

The Company’s assumption regarding the expected long-term rate of return on plan assets is 7.5% (Retirement Plan) and 7.0% (other post-retirement benefits), effective for fiscal 2015. The return assumption reflects the anticipated long-term rate of return on the plan’s current and future assets. The Company utilizes projected capital market conditions and the plan’s target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

The long-term investment objective of the Retirement Plan trust, the VEBA trusts and the 401(h) accounts is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). The target allocation for the Retirement Plan is 40-60% equity securities, 35-55% fixed income securities and 5-20% other. The target allocation for the VEBA trusts (including 401(h) accounts) is 40-60% equity securities, 40-60% fixed income securities and 0-15% other. Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trusts, VEBA trusts and the 401(h) accounts have no significant concentrations of risk in any one country (other than the United States), industry or entity.

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

The discount rate which is used to present value the future benefit payment obligations of the Retirement Plan and the Company's other post-retirement benefits is 4.25% as of September 30, 2014. The discount rate which is used to present value the future benefit payment obligations of the Non-Qualified benefit plans is 3.50% as of September 30, 2014. The Company utilizes the Mercer Yield Curve Above Mean Model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments. In determining the spot rates, the model will exclude coupon interest rates that are in the lower 50th percentile based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities.

Note I — Commitments and Contingencies

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory requirements.

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2014, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be approximately $14.0 million. The main component of this liability is discussed below under "Former Manufactured Gas Plant Sites." This estimated liability has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at September 30, 2014. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 13 years. Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could adversely impact the Company.

(i) Former Manufactured Gas Plant Sites

The Company has incurred investigation and/or clean-up costs at several former manufactured gas plant sites in New York and Pennsylvania. The Company continues to be responsible for future ongoing monitoring and long-term maintenance at two sites.

The most significant ongoing clean-up matter currently facing the Company is a former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. As a

result of this work, the Company submitted to the NYDEC a proposal to amend the NYDEC's Record of Decision remedy for the site. In April 2013, the NYDEC approved the Company's proposed amendment. Final remedial design work for the site has begun. An estimated minimum liability for remediation of this site of $12.6 million has been recorded.

Other

The Company, in its Utility segment, Energy Marketing segment, and Exploration and Production segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. The majority of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $263.8 million in 2015, $66.7 million in 2016, $91.8 million in 2017, $91.8 million in 2018, $82.1 million in 2019 and $845.1 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of compressors, drilling rigs, buildings, meters and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $16.0 million in 2015, $5.8 million in 2016, $5.7 million in 2017, $5.6 million in 2018, $5.3 million in 2019 and $2.4 million thereafter.

The Company, in its Pipeline and Storage segment and Gathering segment, has entered into several contractual commitments associated with various pipeline, compressor and gathering system expansion projects. As of September 30, 2014, the future contractual commitments related to the expansion projects are $103.9 million in 2015 and $0.5 million in 2016. There are no contractual commitments extending beyond 2016.

The Company, in its Exploration and Production segment, has entered into contractual obligations associated with hydraulic fracturing and fuel. The future contractual commitments during the next three years are as follows: $95.3 million in 2015, $24.0 million in 2016 and $0.2 million in 2017. There are no contractual commitments extending beyond 2017.

The Company, in its Utility segment, has entered into contractual obligations associated with the replacement of its legacy mainframe systems. The future contractual commitments during the next two years are as follows: $21.0 million in 2015 and $5.0 million in 2016. There are no contractual commitments extending beyond 2016.

The Company is involved in other litigation arising in the normal course of business. In addition to the regulatory matters discussed in Note C — Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business. These other litigation and regulatory matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, an estimate of the possible loss or range of loss, if any, cannot be made at this time.

Note J — Business Segment Information

The Company reports financial results for five segments: Exploration and Production, Pipeline and Storage, Gathering, Utility and Energy Marketing. The division of the Company's operations into reportable segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors.

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The Exploration and Production segment, through Seneca, is engaged in exploration for, and development and purchase of, natural gas and oil reserves in California, the Appalachian region of the United States and Kansas.
The Pipeline and Storage segment operations are regulated by the FERC for both Supply Corporation and Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers (including NFR), exploration and production companies (including Seneca) and pipeline companies in the northeastern United States markets. Empire transports natural gas to major industrial companies, utilities (including Distribution Corporation) and power producers in New York State.
The Gathering segment is comprised of Midstream Corporation's operations. Midstream Corporation builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region and currently provides gathering services to Seneca.
The Utility segment operations are regulated by the NYPSC and the PaPUC and are carried out by Distribution Corporation. Distribution Corporation sells natural gas to retail customers and provides natural gas transportation services in western New York and northwestern Pennsylvania.
The Energy Marketing segment is comprised of NFR's operations. NFR 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.

The data presented in the tables below reflects financial information for the segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A — Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. The Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income. Energy Marketing segment revenue from external customers and net income for the year ended September 30, 2014 reflect the impact of $8.5 million and $0.6 million, respectively, of unbilled revenue and related incremental margin (net of tax). In prior periods, Energy Marketing segment revenues and related purchased gas costs were recorded when billed, resulting in a one month lag. The impact of not recording unbilled revenue and related costs was immaterial in all prior periods.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS - (Continued)

	Year Ended September 30, 2014								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$804,096	$200,664	$673	$831,156	$271,993	$2,108,582	$3,532	$967	$2,113,081
Intersegment Revenues	$—	$83,744	$69,937	$18,462	$1,159	$173,302	$—	$(173,302)	$—
Interest Income	$1,909	$284	$120	$3,010	$173	$5,496	$106	$(1,432)	$4,170
Interest Expense	$42,232	$26,428	$1,726	$27,693	$31	$98,110	$6	$(3,839)	$94,277
Depreciation, Depletion and Amortization	$296,210	$36,642	$6,116	$43,594	$197	$382,759	$344	$678	$383,781
Income Tax Expense (Benefit)	$81,370	$47,100	$23,636	$33,918	$3,761	$189,785	$822	$(993)	$189,614
Segment Profit: Net Income (Loss)	$121,569	$77,559	$32,709	$64,059	$6,631	$302,527	$1,160	$(4,274)	$299,413
Expenditures for Additions to Long-Lived Assets	$602,705	$139,821	$137,799	$88,810	$264	$969,399	$274	$234	$969,907
	At September 30, 2014 (Thousands)								
Segment Assets	$3,100,514	$1,367,181	$326,662	$1,862,850	$76,238	$6,733,445	$86,460	$(80,308)	$6,739,597

	Year Ended September 30, 2013								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Elimination	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$702,937	$178,184	$1,324	$730,319	$211,990	$1,824,754	$3,910	$887	$1,829,551
Intersegment Revenues	$—	$89,424	$33,457	$16,020	$1,384	$140,285	$—	$(140,285)	$—

Interest Income	$1,501	$193	$55	$3,417	$169	$5,335	$115	$(1,115)	$4,335
Interest Expense	$39,745	$26,248	$2,283	$29,076	$36	$97,388	$2	$(3,279)	$94,111
Depreciation, Depletion and Amortization	$243,431	$35,156	$3,945	$42,729	$123	$325,384	$577	$799	$326,760
Income Tax Expense (Benefit)	$95,317	$38,626	$10,287	$31,065	$2,450	$177,745	$529	$(5,516)	$172,758
Segment Profit: Net Income (Loss)	$115,391	$63,245	$13,321	$65,686	$4,589	$262,232	$894	$(3,125)	$260,001
Expenditures for Additions to Long-Lived Assets	$533,129	$56,144	$54,792	$71,970	$595	$716,630	$307	$160	$717,097
	At September 30, 2013 (Thousands)								
Segment Assets	$2,746,233	$1,246,027	$203,323	$1,870,587	$67,267	$6,133,437	$95,793	$(10,883)	$6,218,347

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

	Year Ended September 30, 2012								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$558,180	$172,312	$704	$704,518	$186,579	$1,622,293	$3,603	$957	$1,626,853
Intersegment Revenues	$—	$86,963	$16,771	$14,604	$1,425	$119,763	$—	$(119,763)	$—
Interest Income	$1,493	$199	$1	$2,765	$188	$4,646	$174	$(1,131)	$3,689
Interest Expense	$29,243	$25,603	$1,444	$33,181	$41	$89,512	$294	$(3,566)	$86,240
Depreciation, Depletion and Amortization	$187,624	$38,182	$1,691	$42,757	$90	$270,344	$400	$786	$271,530
Income Tax Expense (Benefit)	$79,050	$37,655	$4,825	$29,110	$1,933	$152,573	$(490)	$(1,529)	$150,554
Segment Profit: Net Income (Loss)	$96,498	$60,527	$6,855	$58,590	$4,169	$226,639	$13	$(6,575)	$220,077
Expenditures for Additions to Long-Lived Assets	$693,810	$144,167	$80,012	$58,284	$770	$977,043	$5	$346	$977,394
	At September 30, 2012 (Thousands)								
Segment Assets	$2,367,485	$1,243,862	$116,756	$2,070,413	$61,968	$5,860,484	$93,178	$(18,520)	$5,935,142

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

Geographic Information	At September 30		
	2014	2013	2012
	(Thousands)		
Long-Lived Assets:			
United States	$6,362,265	$5,769,670	$5,579,566

Note K — Quarterly Financial Data (unaudited)

In the opinion of management, the following quarterly information includes all adjustments necessary for a fair statement of the results of operations for such periods. Per common share amounts are calculated using the weighted average number of shares outstanding during each quarter. The total of all quarters may differ from the per common

share amounts shown on the Consolidated Statements of Income. Those per common share amounts are based on the weighted average number of shares outstanding for the entire fiscal year. Because of the seasonal nature of the Company’s heating business, there are substantial variations in operations reported on a quarterly basis.

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

Quarter Ended	Operating Revenues	Operating Income	Net Income Available for Common Stock		Earnings per Common Share Basic	Diluted
	(Thousands, except per common share amounts)					
2014						
9/30/2014	$366,623	$102,004	$57,431		$0.68	$0.68
6/30/2014	$440,144	$127,013	$64,520		$0.77	$0.76
3/31/2014	$756,242	$180,075	$95,210	(1)	$1.14	$1.12
12/31/2013	$550,072	$160,581	$82,252		$0.98	$0.97
2013						
9/30/2013	$338,863	$96,636	$47,842	(2)	$0.57	$0.57
6/30/2013	$440,008	$127,004	$58,495		$0.70	$0.69
3/31/2013	$597,826	$162,991	$85,720		$1.03	$1.02
12/31/2012	$452,854	$131,207	$67,944		$0.81	$0.81

(1) Includes $3.6 million of income associated with a death benefit gain on life insurance proceeds recorded in the Corporate category.

(2) Includes a $4.7 million refund provision recorded in the Utility segment related to various issues raised in Distribution Corporation's rate proceeding in New York.

Note L — Market for Common Stock and Related Shareholder Matters (unaudited)

At September 30, 2014, there were 12,654 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange. Information related to restrictions on the payment of dividends can be found in Note E — Capitalization and Short-Term Borrowings. The quarterly price ranges (based on intra-day prices) and quarterly dividends declared for the fiscal years ended September 30, 2014 and 2013, are shown below:

	Price Range		Dividends
Quarter Ended	High	Low	Declared
2014			
9/30/2014	$78.79	$65.29	$0.385
6/30/2014	$78.46	$68.50	$0.385
3/31/2014	$77.05	$68.12	$0.375
12/31/2013	$72.53	$65.23	$0.375
2013			
9/30/2013	$69.27	$57.52	$0.375
6/30/2013	$64.58	$56.80	$0.375
3/31/2013	$61.44	$48.51	$0.365
12/31/2012	$55.66	$49.00	$0.365

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

The Company follows authoritative guidance related to oil and gas exploration and production activities that aligns the reserve estimation and disclosure requirements with the requirements of the SEC Modernization of Oil and Gas Reporting rule, which the Company also follows. The SEC rules require companies to value their year-

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

end reserves using an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve month period prior to the end of the reporting period.
The following supplementary information is presented in accordance with the authoritative guidance regarding disclosures about oil and gas producing activities and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30	
	2014	2013
	(Thousands)	
Proved Properties(1)	$3,941,143	$3,393,612
Unproved Properties	141,719	106,085
	4,082,862	3,499,697
Less — Accumulated Depreciation, Depletion and Amortization	1,211,610	919,989
	$2,871,252	$2,579,708

(1) Includes asset retirement costs of $75.7 million and $80.6 million at September 30, 2014 and 2013, respectively.
Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Although the timing of the ultimate evaluation or disposition of the unproved properties cannot be determined, the Company expects the majority of its acquisition costs associated with unproved properties to be transferred into the amortization base by 2020. It expects the majority of its development and exploration costs associated with unproved properties to be transferred into the amortization base by 2015. Following is a summary of costs excluded from amortization at September 30, 2014:

	Total as of September 30, 2014	Year Costs Incurred			
		2014	2013	2012	Prior
	(Thousands)				
Acquisition Costs	$61,712	$7,057	$905	$5,585	$48,165
Development Costs	42,362	39,339	677	1,405	941
Exploration Costs	36,882	36,882	—	—	—
Capitalized Interest	763	763	—	—	—
	$141,719	$84,041	$1,582	$6,990	$49,106

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

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

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
United States			
Property Acquisition Costs:			
Proved	$18,213	$7,575	$13,095
Unproved	7,884	9,274	13,867
Exploration Costs(1)	71,850	49,483	84,624
Development Costs(2)	490,164	460,554	576,397
Asset Retirement Costs	(4,946)	37,546	10,344
	$583,165	$564,432	$698,327

(1) Amounts for 2014, 2013 and 2012 include capitalized interest of $0.7 million, $0.4 million and $1.0 million, respectively.

(2) Amounts for 2014, 2013 and 2012 include capitalized interest of $0.7 million, $0.7 million and $2.0 million, respectively.

For the years ended September 30, 2014, 2013 and 2012, the Company spent $179.9 million, $148.5 million and $216.6 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2014	2013	2012
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $1 for all years presented and transfers to operations of $2,145, $612 and $0, respectively)	$515,080	$371,311	$181,544
Oil, Condensate and Other Liquids	298,179	291,762	307,018
Total Operating Revenues(1)	813,259	663,073	488,562
Production/Lifting Costs	165,534	119,243	83,361
Franchise/Ad Valorem Taxes	20,765	17,200	23,620
Accretion Expense	6,192	3,929	3,084
Depreciation, Depletion and Amortization ($1.82, $1.98 and $2.19 per Mcfe of production)	291,651	238,467	182,759
Income Tax Expense	140,484	120,431	81,904
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$188,633	$163,803	$113,834

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

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

Reserve Quantity Information

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

The Company's Vice President of Reservoir Engineering is the primary technical person responsible for overseeing the Company's reserve estimation process and engaging and overseeing the third party reserve audit. His qualifications include a Bachelor of Science Degree in Petroleum Engineering and over 25 years of Petroleum Engineering experience with both major and independent oil and gas companies. He has maintained oversight of the Company's reserve estimation process for the past eleven years. He is a member of the Society of Petroleum Engineers and a Registered Professional Engineer in the State of Texas.

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

All of the Company's reserve estimates are audited annually by Netherland, Sewell and Associates, Inc. (NSAI). Since 1961, NSAI has evaluated gas and oil properties and independently certified petroleum reserve quantities in the United States and internationally under the Texas Board of Professional Engineers Registration No. F-002699. The primary technical persons (employed by NSAI) that are responsible for leading the audit include a professional engineer registered with the State of Texas (consulting at NSAI since 2004 and with over 5 years of prior industry experience in petroleum engineering) and a professional geoscientist registered in the State of Texas (consulting at NSAI since 2008 with over 11 years of prior industry experience in petroleum geosciences). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2014 and did not identify any problems which would cause it to take exception to those estimates.

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

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

	Gas MMcf U. S. Appalachian Region		West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
September 30, 2011	606,606		68,316	674,922
Extensions and Discoveries	435,460	(1)	638	436,098
Revisions of Previous Estimates	(53,992)		(2,463)	(56,455)
Production	(62,663)	(2)	(3,468)	(66,131)
September 30, 2012	925,411		63,023	988,434
Extensions and Discoveries	360,922	(1)	702	361,624
Revisions of Previous Estimates	53,038		112	53,150
Production	(100,633)	(2)	(3,060)	(103,693)
September 30, 2013	1,238,738		60,777	1,299,515
Extensions and Discoveries	446,821	(1)	—	446,821
Revisions of Previous Estimates	43,690		1,358	45,048
Production	(139,097)	(2)	(3,210)	(142,307)
Purchases of Minerals in Place	33,986		—	33,986
Sale of Minerals in Place	(76)		(103)	(179)
September 30, 2014	1,624,062		58,822	1,682,884
Proved Developed Reserves:				
September 30, 2011	350,458		63,965	414,423
September 30, 2012	544,560		59,923	604,483
September 30, 2013	807,055		59,862	866,917
September 30, 2014	1,119,901		57,907	1,177,808
Proved Undeveloped Reserves:				
September 30, 2011	256,148		4,351	260,499
September 30, 2012	380,851		3,100	383,951
September 30, 2013	431,683		915	432,598
September 30, 2014	504,161		915	505,076

(1) Extensions and discoveries include 435 Bcf (during 2012), 355 Bcf (during 2013) and 442 Bcf (during 2014), of Marcellus Shale gas in the Appalachian Region.

(2) Production includes 55,812 MMcf (during 2012), 93,999 MMcf (during 2013) and 131,590 MMcf (during 2014), from Marcellus Shale fields (which exceed 15% of total reserves).

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

	Oil Mbbl U. S. Appalachian Region	West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:			
September 30, 2011	279	43,066	43,345
Extensions and Discoveries	28	1,229	1,257
Revisions of Previous Estimates	35	1,095	1,130
Production	(36)	(2,834)	(2,870)
September 30, 2012	306	42,556	42,862
Extensions and Discoveries	—	2,443	2,443
Revisions of Previous Estimates	5	(881)	(876)
Production	(28)	(2,803)	(2,831)
September 30, 2013	283	41,315	41,598
Extensions and Discoveries	18	1,521	1,539
Revisions of Previous Estimates	(17)	(1,677)	(1,694)
Production	(31)	(3,005)	(3,036)
Purchases of Minerals in Place	—	83	83
Sales of Minerals in Place	—	(13)	(13)
September 30, 2014	253	38,224	38,477
Proved Developed Reserves:			
September 30, 2011	274	37,306	37,580
September 30, 2012	306	38,138	38,444
September 30, 2013	283	38,082	38,365
September 30, 2014	253	37,002	37,255
Proved Undeveloped Reserves:			
September 30, 2011	5	5,760	5,765
September 30, 2012	—	4,418	4,418
September 30, 2013	—	3,233	3,233
September 30, 2014	—	1,222	1,222

The Company’s proved undeveloped (PUD) reserves increased from 452 Bcfe at September 30, 2013 to 512 Bcfe at September 30, 2014. PUD reserves in the Marcellus Shale increased from 432 Bcf at September 30, 2013 to 504 Bcf at September 30, 2014. The Company’s total PUD reserves were 27% of total proved reserves at September 30, 2014, down from 29% of total proved reserves at September 30, 2013.

The Company’s PUD reserves increased from 410 Bcfe at September 30, 2012 to 452 Bcfe at September 30, 2013. PUD reserves in the Marcellus Shale increased from 381 Bcf at September 30, 2012 to 432 Bcf at September 30, 2013. The Company’s total PUD reserves were 29% of total proved reserves at September 30, 2013, down from 33% of total proved reserves at September 30, 2012.

The increase in PUD reserves in 2014 of 60 Bcfe is a result of 290 Bcfe in new PUD reserve additions (288 Bcfe from the Marcellus Shale), 20 Bcfe in PUD reserves acquired, 12 Bcfe in upward revisions to remaining PUD reserves, offset by 229 Bcfe in PUD conversions to developed reserves and 33 Bcfe in PUD reserves removed. The PUD reserves removed were primarily in the Marcellus Shale (24 Bcfe) in Seneca’s non-operated joint venture in Clearfield County where the operator had previously drilled and cased the horizontal wells to total depth and

does not appear now to have firm plans for their completion. An additional 9 Bcfe (1,501 Mbbl) of PUD reserves were removed at the Midway Sunset field in the Tulare reservoir as the Company has no near term plans to develop these reserves as it is employing capital elsewhere.

The increase in PUD reserves in 2013 of 42 Bcfe is a result of 221 Bcfe in new PUD reserve additions (219 Bcfe from the Marcellus Shale), offset by 160 Bcfe in PUD conversions to developed reserves and 19 Bcfe in downward PUD revisions. The downward revisions were primarily due to reductions to planned lateral lengths for several horizontal wells in the Marcellus Shale.

The Company invested $180 million during the year ended September 30, 2014 to convert 229 Bcfe (248 Bcfe including revisions) of PUD reserves to developed reserves. This represents 51% of the PUD reserves booked at September 30, 2013. The Company invested $149 million during the year ended September 30, 2013 to convert 160 Bcfe (171 Bcfe including revisions) of September 30, 2012 PUD reserves to proved developed reserves. This represented 39% of the PUD reserves booked at September 30, 2012. In 2015, the Company estimates that it will invest approximately $239 million to develop its PUD reserves. The Company is committed to developing its PUD reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting. Since that rule, and over the last five years, the Company developed 19% of its beginning year PUD reserves in fiscal 2010, 47% of its beginning year PUD reserves in fiscal 2011, 33% of its beginning year PUD reserves in fiscal 2012, 39% of its beginning year PUD reserves in fiscal 2013 and 51% of its beginning year PUD reserves in fiscal 2014.

At September 30, 2014, the Company does not have a material concentration of proved undeveloped reserves that have been on the books for more than five years at the corporate level, country level or field level. All of the Company's proved reserves are in the United States.

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

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company's oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, in accordance with the SEC's final rule on Modernization of Oil and Gas Reporting, it is based on the unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period and costs adjusted only for existing contractual changes. It assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions. The standardized measure is intended instead to provide a means for comparing the value of the Company's proved reserves at a given time with those of other oil- and gas-producing companies than is provided by a simple comparison of raw proved reserve quantities.

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

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
United States			
Future Cash Inflows	$10,001,545	$8,943,942	$7,373,129
Less:			
Future Production Costs	2,795,657	2,334,393	1,919,530
Future Development Costs	790,033	749,876	619,573
Future Income Tax Expense at Applicable Statutory Rate	2,434,370	2,113,101	1,812,055
Future Net Cash Flows	3,981,485	3,746,572	3,021,971
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,914,607	1,780,206	1,552,180
Standardized Measure of Discounted Future Net Cash Flows	$2,066,878	$1,966,366	$1,469,791

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

	Year Ended September 30		
	2014	2013	2012
	(Thousands)		
United States			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	$1,966,366	$1,469,791	$1,524,157
Sales, Net of Production Costs	(626,960)	(526,630)	(381,581)
Net Changes in Prices, Net of Production Costs	(38,723)	339,655	(385,019)
Extensions and Discoveries	381,008	390,255	224,474
Changes in Estimated Future Development Costs	68,731	6,117	29,627
Purchases of Minerals in Place	34,705	—	—
Sales of Minerals in Place	(691)	—	—
Previously Estimated Development Costs Incurred	179,502	148,535	252,967
Net Change in Income Taxes at Applicable Statutory Rate	(231,807)	(130,574)	(19,280)
Revisions of Previous Quantity Estimates	55,184	34,864	103,472
Accretion of Discount and Other	279,563	234,353	120,974
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$2,066,878	$1,966,366	$1,469,791

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts(1)	Deductions (2)	Balance at End of Period
Year Ended September 30, 2014					
Allowance for Uncollectible Accounts	$27,144	$10,856	$3,241	$9,430	$31,811
Year Ended September 30, 2013					
Allowance for Uncollectible Accounts	$30,317	$5,568	$2,390	$11,131	$27,144
Year Ended September 30, 2012					
Allowance for Uncollectible Accounts	$31,039	$9,183	$1,946	$11,851	$30,317

(1) Represents the discount on accounts receivable purchased in accordance with the Utility segment's 2005 New York rate agreement.

(2) Amounts represent net accounts receivable written-off.

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

None.

Item 9A Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2014.

Management's Annual Report on Internal Control over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2014. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control — Integrated Framework, published in 1992. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2014.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report

on the effectiveness of the Company's internal control over financial reporting as of September 30, 2014. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B Other Information

None.

PART III

Item 10 Directors, Executive Officers and Corporate Governance

The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors for Three-Year Terms to Expire in 2018," "Directors Whose Terms Expire in 2017," "Directors Whose Terms Expire in 2016," and "Section 16(a) Beneficial Ownership Reporting Compliance" and is incorporated herein by reference. The information concerning corporate governance will be set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

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

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

Item 11 Executive Compensation

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

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

Equity Compensation Plan Information

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

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

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

(b) Security Ownership of Management

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

(c) Changes in Control

None.

Item 13 Certain Relationships and Related Transactions, and Director Independence

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

Item 14 Principal Accountant Fees and Services

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

PART IV

Item 15 Exhibits and Financial Statement Schedules

(a)1. Financial Statements

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

(a)2. Financial Statement Schedules

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

(a)3. Exhibits

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

Exhibit Number	Description of Exhibits
3(i)	Articles of Incorporation:

Exhibit Number	Description of Exhibits
•	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998; Certificate of Amendment of Restated Certificate of Incorporation dated March 14, 2005 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 2013)
3(ii)	By-Laws:
•	National Fuel Gas Company By-Laws as amended June 12, 2014 (Exhibit 3.1, Form 8-K dated June 16, 2014)
4	Instruments Defining the Rights of Security Holders, Including Indentures:
•	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
•	Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
•	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992)
•	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992)
•	Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
•	Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993)
•	Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999)
•	Officer’s Certificate establishing 6.50% Notes due 2018, dated April 11, 2008 (Exhibit 4.1, Form 10-Q for the quarterly period ended June 30, 2008)
•	Officer’s Certificate establishing 8.75% Notes due 2019, dated April 6, 2009 (Exhibit 4.4, Form 8-K dated April 6, 2009)
•	Officer’s Certificate establishing 4.90% Notes due 2021, dated December 1, 2011 (Exhibit 4.4, Form 8-K dated December 1, 2011)
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Officers Certificate establishing 3.75% Notes due 2023, dated February 15, 2023 (Exhibit 4.1.1, Form 8-K dated February 15, 2013)

- Amended and Restated Rights Agreement, dated as of December 4, 2008, between the Company and The Bank of New York Mellon (formerly The Bank of New York), as rights agent (Exhibit 4.1, Form 8-K dated December 4, 2008)

- Letter of Appointment of Wells Fargo Bank, National Association, as Successor Rights Agent, dated July 18, 2012 (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 2012)

Exhibit Number	Description of Exhibits
10	Material Contracts:
•	Amended and Restated Credit Agreement, dated as of January 6, 2012, among the Company, the Lenders Party Thereto, and JPMorgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2012)
•	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006)
•	Resolutions adopted by the National Fuel Gas Company Board of Directors on February 21, 2008 regarding director stock ownership guidelines (Exhibit 10.5, Form 10-Q for the quarterly period ended March 31, 2008)
	Management Contracts and Compensatory Plans and Arrangements:
•	Director Services Agreement between the Company and David F. Smith, dated March 13, 2014 (Exhibit 10.1, Form 8-K dated March 13, 2014)
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of David P. Bauer, Karen M. Camiolo, Carl M. Carlotti, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008)
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, Seneca Resources Corporation and Matthew D. Cabell (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2008)
•	Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006)
•	Description of September 17, 2009 restricted stock award (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2009)
•	Description of post-employment medical and prescription drug benefits (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2009)
•	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006)
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Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006)

- Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006)
- Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2008)
- Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2008)
- Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2011)

Exhibit Number	Description of Exhibits
•	Form of Restricted Stock Award Notice under the National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2010)
•	Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 8-K dated March 17, 2010)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2010)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2010)
•	Form of Restricted Stock Unit Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2012)
•	Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2008)
•	Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2011)
•	National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2012)
•	Description of performance goals under the Amended and Restated National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2012)
•	National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective December 5, 2012 (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2012)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995)

- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996)
- National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997)

Exhibit Number	Description of Exhibits
•	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005)
•	Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997)
•	Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998)
•	Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998)
•	Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005)
•	National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007)
•	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999)
•	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999)

- Life Insurance Premium Agreement, dated September 17, 2009, between the Company and David F. Smith (Exhibit 10.1, Form 8-K dated September 23, 2009)
- National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004)
- National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995)

Exhibit Number	Description of Exhibits
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007 (Exhibit 10.4, Form 10-K for the fiscal year ended September 30, 2007)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010)
•	National Fuel Gas Company 2012 Performance Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 2012)
•	Description of long-term performance incentives for the period October 1, 2011 to September 30, 2014 under the National Fuel Gas Company 2012 Performance Incentive Program (Item 5.02, Form 8-K dated March 13, 2012)
•	National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2009)
•	Description of assignment of interests in certain life insurance policies (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2006)
•	Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006)
•	Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006)
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Description of 2014 performance goals under the National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2013)

- Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2013)

Exhibit Number	Description of Exhibits
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2013)
•	Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2013)
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2010 through 2014
21	Subsidiaries of the Registrant
23	Consents of Experts:
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
23.2	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99	Additional Exhibits:
99.1	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
99.2	Company Maps
101	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the years ended September 30, 2014, 2013 and 2012, (ii) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2014, 2013 and 2012 (iii) the Consolidated Balance Sheets at September 30, 2014 and September 30, 2013, (iv) the Consolidated Statements of Cash Flows for the years ended September 30, 2014, 2013 and 2012 and (v) the Notes to Consolidated Financial Statements.

• Incorporated herein by reference as indicated.

All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K.

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

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

National Fuel Gas Company
(Registrant)

By /s/ R. J. Tanski
R. J. Tanski
President and Chief Executive Officer

Date: November 21, 2014

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

Signature	Title	
/s/ D. F. Smith D. F. Smith	Chairman of the Board and Director	Date: November 21, 2014
/s/ P. C. Ackerman P. C. Ackerman	Director	Date: November 21, 2014
/s/ D. C. Carroll D. C. Carroll	Director	Date: November 21, 2014
/s/ R. D. Cash R. D. Cash	Director	Date: November 21, 2014
/s/ S. E. Ewing S. E. Ewing	Director	Date: November 21, 2014
/s/ R. W. Jibson R. W. Jibson	Director	Date: November 21, 2014
/s/ C. G. Matthews C. G. Matthews	Director	Date: November 21, 2014
/s/ J. W. Shaw J. W. Shaw	Director	Date: November 21, 2014
/s/ R. J. Tanski R. J. Tanski	President, Chief Executive Officer and Director	Date: November 21, 2014
/s/ D. P. Bauer D. P. Bauer	Treasurer and Principal Financial Officer	Date: November 21, 2014
/s/ K. M. Camiolo	Controller and Principal	Date: November 21, 2014

Accounting Officer

K. M. Camiolo