NATIONAL FUEL GAS CO
Form 10-K
November 23, 2011
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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, 2011

¨ **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	**14221**
Williamsville, New York	*(Zip Code)*
(Address of principal executive offices)	

(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, $1 Par Value, 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 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. ¨

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 $5,925,830,000 as of March 31, 2011.

Common Stock, $1 Par Value, outstanding as of October 31, 2011: 82,844,910 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive Proxy Statement for its 2012 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

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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

Highland Highland Forest Resources, Inc.

Horizon Horizon Energy Development, Inc.

Horizon B.V. Horizon Energy Development B.V.

Horizon LFG Horizon LFG, Inc.

Horizon Power Horizon Power, Inc.

Midstream Corporation National Fuel Gas Midstream Corporation

Model City Model City Energy, LLC

National Fuel National Fuel Gas Company

NFR National Fuel Resources, Inc.

Registrant National Fuel Gas Company

SECI Seneca Energy Canada Inc.

Seneca Seneca Resources Corporation

Seneca Energy Seneca Energy II, LLC

Supply Corporation National Fuel Gas Supply Corporation

Regulatory Agencies

EPA United States Environmental Protection Agency

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

IASB International Accounting Standards Board

NYDEC New York State Department of Environmental Conservation

NYPSC State of New York Public Service Commission

PaPUC Pennsylvania Public Utility Commission

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.

Cashout revenues A cash resolution of a gas imbalance whereby a customer pays Supply Corporation for gas the customer receives in excess of amounts delivered into Supply Corporation s system by the customer s shipper.

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.

Degree day A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.

Derivative A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and

no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.

Development costs Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.

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

Dodd-Frank Act Dodd-Frank Wall Street Reform and Consumer Protection Act.

Dth Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.

Exchange Act Securities Exchange Act of 1934, as amended

Expenditures for long-lived assets Includes capital expenditures, stock acquisitions and/or investments in partnerships.

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

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

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

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.

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.

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

MMcf Million cubic feet (of natural gas)

MMcfe Million cubic feet equivalent

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

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

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

Order 636 An order issued by FERC entitled Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 284 of the Commission s Regulations.

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

PUHCA 1935 Public Utility Holding Company Act of 1935

PUHCA 2005 Public Utility Holding Company Act of 2005

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.

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This Form 10-K contains forward-looking statements as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-K at Item 7, MD&A, under the heading Safe Harbor for Forward-Looking Statements. Forward-looking statements are all statements other than statements of historical fact, 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 and other projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words anticipates, estimates, expects, forecasts, intends, plans, predicts, projects, believes, seeks, will, may and similar expressions.

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 and reports financial results for four business segments.

1. 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 731,600 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.

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 157-mile pipeline that extends from the United States/Canadian border at the Niagara River near Buffalo, New York to near Syracuse, New York, and the Empire Connector, which is a 76-mile pipeline extension from near Rochester, New York to an interconnection with the unaffiliated Millennium Pipeline near Corning, New York. The Millennium Pipeline serves the New York City area. The Empire Connector was placed into service on December 10, 2008.

3. The Exploration and Production segment operations are carried out by Seneca Resources Corporation (Seneca), a Pennsylvania corporation, and by Seneca Western Minerals Corp., a Nevada corporation and an indirect, wholly owned subsidiary of Seneca. Seneca is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California and in the Appalachian region of the United States. At September 30, 2011, the Company had U.S. proved developed and undeveloped reserves of 43,345 Mbbl of oil and 674,922 MMcf of natural gas.

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4. 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 K Business Segment Information.

The Company s other direct wholly owned subsidiaries or businesses are not included in any of the four reported business segments and include the following active companies:

Seneca s Northeast Division, which markets timber from Appalachian land holdings. At September 30, 2011, the Company owned approximately 95,000 acres of timber property and managed an additional 3,424 acres of timber cutting rights; and

National Fuel Gas Midstream Corporation (Midstream Corporation), a Pennsylvania corporation formed to build, own and operate natural gas processing and pipeline gathering facilities in the Appalachian region.

No single customer, or group of customers under common control, accounted for more than 10% of the Company s consolidated revenues in 2011.

Rates and Regulation

The Registrant is a holding company as defined under PUHCA 2005. PUHCA 2005 repealed PUHCA 1935, to which the Company was formerly subject, and granted the FERC and state public utility commissions access to certain books and records of companies in holding company systems. Pursuant to the FERC s regulations under PUHCA 2005, the Company and its subsidiaries are exempt from the FERC s books and records regulations under PUHCA 2005.

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 Utility Segment

The Utility segment contributed approximately 24.5% of the Company s 2011 net income available for common stock.

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Additional discussion of the Utility segment appears below in this Item 1 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 Pipeline and Storage Segment

The Pipeline and Storage segment contributed approximately 12.2% of the Company s 2011 net income available for common stock.

Supply Corporation has service agreements for all of its firm storage capacity, totaling 68,403 MDth. The Utility segment has contracted for 29,743 MDth or 43.5% of the total firm storage capacity, and the Energy Marketing segment accounts for another 4,810 MDth or 7.0% of the total firm storage capacity. Nonaffiliated customers have contracted for the remaining 33,850 MDth or 49.5% of the total firm storage capacity. The majority of Supply Corporation s storage and transportation services are performed under contracts that allow Supply Corporation or the shipper to terminate the contract upon six or twelve months notice effective at the end of the contract term. The contracts also typically include evergreen language designed to allow the contracts to extend year-to-year at the end of the primary term. At the beginning of 2012, 94.5% of Supply Corporation s total firm storage capacity was committed under contracts that, subject to 2011 shipper or Supply Corporation notifications, could have been terminated effective in 2012. Supply Corporation received storage contract termination notifications in 2011 totaling approximately 564 MDth of storage capacity. Supply Corporation expects to remarket this capacity with service beginning April 1, 2012.

Supply Corporation s firm transportation capacity is not a fixed quantity, due to the diverse web-like nature of its pipeline system, and 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 2,115 MDth per day (contracted transportation capacity), compared to 2,134 MDth per day last year. The Utility segment accounts for approximately 1,055 MDth per day or 49.9% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 130 MDth per day or 6.1% of contracted transportation capacity. The remaining 930 MDth or 44.0% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2012, 52.0% of Supply Corporation s contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2012 or, subject to 2011 shipper or Supply Corporation notifications, could have been terminated effective in 2012. Based on contract expirations and termination notices received in 2011 for 2012 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to increase 0.8% in 2012. Similarly, 33.3% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2012 or, subject to 2011 shipper or Supply Corporation notifications, could have been terminated effective in 2012. Based on contract expirations and termination notices received in 2011 for 2012 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to increase 4.8% in 2012. The relatively high price of natural gas supplies available at Supply Corporation s receipt point on the United States/Canadian border at Niagara, together with shifting gas supply dynamics, have reduced the amount of firm capacity Supply Corporation contracts from Niagara. However, Supply Corporation has been successful in marketing and obtaining long-term firm contracts for transportation capacity designed to move Marcellus Shale production to market. Specifically, in 2012, Supply Corporation expects to add 160 MDth per day of contracted incremental transportation associated with its Line N 2011 project, along with several other Marcellus-related transportation contracts. Supply Corporation expects this trend to continue in 2013 as additional transportation contracts commence in conjunction with Supply Corporation s Northern Access and Line N 2012 expansion projects.

At the beginning of 2012, Empire had service agreements in place for firm transportation capacity totaling up to approximately 663 MDth per day, compared to 686 MDth per day at the beginning of 2011. The majority of Empire s transportation services are performed under contracts that allow Empire or the shipper to terminate the contract upon six or twelve months notice effective at the end of the contract term.

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The contracts also typically include evergreen language designed to allow the contracts to extend year-to-year at the end of the primary term. At the beginning of 2012, most of Empire s firm contracted capacity (92.3%) was contracted as long-term full-year deals. Four of those contracts expire during 2012, representing approximately 1.7% of Empire s firm contracted capacity. In addition, Empire has some seasonal (winter-only) contracts that extend for multiple years, representing 2.5% of Empire s firm contracted capacity. One of those multi-year, seasonal contracts expires during 2012, representing approximately 0.6% of Empire s firm contracted capacity. Arrangements for the remaining 5.2% of Empire s firm contracted capacity are single-season or single-year contracts that potentially expire early in 2013, depending on whether Empire issues or receives termination notices during 2012. At the beginning of 2012, the Utility segment accounted for 6.3% of Empire s firm contracted capacity, and the Energy Marketing segment accounted for 2.0% of Empire s firm contracted capacity, with the remaining 91.7% of Empire s firm contracted capacity subject to contracts with nonaffiliated customers.

The relatively high price of natural gas supplies available at Empire s receipt point on the United States/Canadian border at Chippawa, together with shifting gas supply dynamics, have reduced the amount of firm capacity Empire contracts from Chippawa. However, Empire has been successful in marketing and obtaining long-term firm contracts for transportation capacity designed to move Marcellus Shale production to market. Specifically, in early 2012, Empire expects to add two long-term contracts for firm transportation service associated with its Tioga County extension project. These contracts are for increasing amounts of firm capacity beginning at 230 MDth per day and increasing over the next 18 months to 350 MDth per day. In addition, in early 2012, Empire expects to add two other seasonal (winter-only) contracts totaling 23 MDth per day of incremental firm capacity; these agreements will expire in 2012.

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 Exploration and Production Segment

The Exploration and Production segment contributed approximately 48.0% of the Company s 2011 net income available for common stock.

Additional discussion of the Exploration and Production segment appears below 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 Energy Marketing Segment

The Energy Marketing segment contributed approximately 3.4% of the Company s 2011 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 contributed approximately 11.9% of the Company s 2011 net income available for common stock.

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.

Discontinued Operations

In September 2010, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. The Company s landfill gas operations were maintained under

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the Company s wholly owned subsidiary, Horizon LFG, which owned and operated these short distance landfill gas pipeline companies. These operations are presented in the Company s financial statements as discontinued operations.

Additional discussion of the Company s discontinued operations appears in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

Sources and Availability of Raw Materials

Natural gas is the principal raw material for the Utility segment. In 2011, the Utility segment purchased 72.7 Bcf of gas for delivery to its customers. Gas purchased from producers and suppliers in the United States and Canada under firm contracts (seasonal and longer) accounted for 57% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 43% of the Utility segment s 2011 purchases. Purchases from Chevron Natural Gas (17%), South Jersey Resources Group, LLC (13%) and Tenaska Marketing Ventures (13%) accounted for 43% of the Utility s 2011 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2011.

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 southwestern and mid-continent regions of the United States as well as in Canada. Additional discussion of proposed pipeline projects appears below under Competition: The Pipeline and Storage Segment and in Item 7, MD&A.

The 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 K Business Segment Information and Note O Supplementary Information for Oil and Gas Producing Activities.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2011, this segment purchased 53.9 Bcf of gas, including 52.9 Bcf for delivery to its customers. The remaining 1.0 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 or in Canada.

Competition

Competition in the natural gas industry exists among providers of natural gas, as well as between natural gas and other sources of energy. The natural gas industry has gone through various stages of regulation. Apart from environmental and state utility commission regulation, the natural gas industry has experienced considerable deregulation. This has enhanced the competitive position of natural gas relative to other energy sources, such as fuel oil or electricity, since some of the historical regulatory impediments to adding customers and responding to market forces have been removed. In addition, management believes that the environmental advantages of natural gas have enhanced its competitive position relative to other fuels.

The electric industry has been moving toward a more competitive environment as a result of changes in federal law in 1992 and initiatives undertaken by the FERC and various states. It remains unclear what the impact of any further restructuring in response to legislation or other events may be.

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 Utility Segment

The changes precipitated by the FERC s restructuring of the natural gas industry in Order No. 636, which was issued in 1992, continue to reshape the roles of the gas utility industry and the state regulatory commissions. With respect to gas commodity service, in both New York and Pennsylvania, Distribution

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Corporation has retained a substantial majority of small sales customers. Almost all large-volume load, however, is served by unregulated retail marketers. In New York, approximately 20%, and in Pennsylvania, approximately 10%, of Distribution Corporation s small-volume residential and commercial customers purchase their supplies from unregulated marketers. 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 delivery rates and charges, not through charges for gas commodity service. Over the longer run, however, rate design changes resulting from further customer migration to marketer service (e.g., unbundling) can 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 sources and uses of natural gas or new services, rates and contracts.

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. Its facilities are 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 offer the opportunity for increased transportation services. Supply Corporation is pursuing its Northern Access pipeline expansion project 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 this project, 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 gas received at the Niagara River at Chippawa and, with further expansion, Appalachian-sourced gas. Empire s location provides it the opportunity to compete for an increased share of the gas transportation markets. As noted above, Empire has constructed the Empire Connector project, which expands its natural gas pipeline and enables Empire to serve new markets in New York and elsewhere in the Northeast. Empire is also pursuing its Tioga County Extension project, which will stretch 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 is designed to facilitate transportation of Marcellus Shale gas to key markets of Canada and the northeastern United States. For further discussion of this project, refer to Item 7, MD&A under the headings Investing Cash Flow and Rate and Regulatory Matters.

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.

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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 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 revenues. 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 1,827 full-time employees at September 30, 2011. This compares to 1,859 employees in the Company s operations at September 30, 2010.

The Company has agreements in place with collective bargaining units in New York and Pennsylvania. The agreements in New York are scheduled to expire in February 2013 and the agreements in Pennsylvania are scheduled to expire in April 2014 and May 2014.

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.

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Executive Officers of the Company as of November 15, 2011(1)

Name and Age (as of November 15, 2011)	Current Company Positions and Other Material Business Experience During Past Five Years
David F. Smith (58)	Chairman of the Board of Directors of the Company since March 2010 and Chief Executive Officer of the Company since February 2008. Mr. Smith previously served as President of the Company from February 2006 through June 2010; Chief Operating Officer of the Company from February 2006 through January 2008; President of Supply Corporation from April 2005 through June 2008; and President of Empire from September 2005 through July 2008.
Ronald J. Tanski (59)	President and Chief Operating Officer of the Company since July 2010. Mr. Tanski previously served as Treasurer and Principal Financial Officer of the Company from April 2004 through June 2010; President of Supply Corporation from July 2008 through June 2010; President of Distribution Corporation from February 2006 through June 2008; and Treasurer of Distribution Corporation from April 2004 through July 2008.
Matthew D. Cabell (53)	Senior Vice President of the Company since July 2010 and President of Seneca since December 2006. Prior to joining Seneca, Mr. Cabell served as Executive Vice President and General Manager of Marubeni Oil & Gas (USA) Inc., an exploration and production company, from June 2003 to December 2006. Mr. Cabell s prior employer is not a subsidiary or affiliate of the Company.
Anna Marie Cellino (58)	President of Distribution Corporation since July 2008. Ms. Cellino previously served as Secretary of the Company from October 1995 through June 2008; Secretary of Distribution Corporation from September 1999 through June 2008; and Senior Vice President of Distribution Corporation from July 2001 through June 2008.
John R. Pustulka (59)	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 (42)	Treasurer and Principal Financial Officer of the Company since July 2010; 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 (52)	Controller and Principal Accounting Officer of the Company since April 2004; and Controller of Distribution Corporation and Supply Corporation since April 2004.
Carl M. Carlotti (56)	Senior Vice President of Distribution Corporation since January 2008. Mr. Carlotti previously served as Vice President of Distribution Corporation from October 1998 to January 2008.
Paula M. Ciprich (51)	Secretary of the Company since July 2008; General Counsel of the Company since January 2005; Secretary of Distribution Corporation since July 2008. Ms. Ciprich previously served as General Counsel of Distribution Corporation from February 1997 through February 2007 and as Assistant Secretary of Distribution Corporation from February 1997 through June 2008.
Donna L. DeCarolis (52)	Vice President Business Development of the Company since October 2007. Ms. DeCarolis previously served as President of NFR from January 2005 to October 2007 and as Secretary of NFR from March 2002 to October 2007.
James D. Ramsdell (56)	Senior Vice President 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.

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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 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 Standard & Poor s Ratings Services, 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, anticipated reductions in funding of the federal Low Income Home Energy Assistance Program could result in increased bad debt expense and reduced earnings for the Company. Any of these events could have a material adverse effect on the Company s results of operations, financial condition and cash flows.

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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.

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 Resources, 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. State commissions can also petition the FERC to investigate whether Supply Corporation s and Empire s rates are still just and reasonable, 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 the wake of certain pipeline accidents not involving the Company, new laws or regulations may be adopted regarding pipeline safety. Proposals have been made at the federal level with respect to matters such as reporting of pipeline accidents, increased fines for pipeline safety violations, 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. In addition, 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 projects that it may issue a Notice of Proposed Rulemaking by December 2012. If as a result of 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.

The Company s liquidity, and in certain circumstances, its earnings, could be adversely affected by the cost of purchasing natural gas during periods in which natural gas prices are rising significantly.

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. Nevertheless, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of the Company s capital resources. The Company has issued commercial paper and used short-term borrowings in the past to temporarily finance storage inventories and purchased gas costs, and although the Company expects to do so in the future, it may not be able to access the markets for such borrowings at attractive interest rates or at all. 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. Due to the nature of the regulatory process, there is a risk of a disallowance of full recovery of these costs during any period in which there has been a substantial upward spike in these costs. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings. In addition, even when Distribution Corporation is allowed full recovery of these purchased gas costs, during periods when natural gas prices are significantly higher than historical levels, customers may have trouble paying the resulting higher bills, and Distribution Corporation s bad debt expenses may increase and ultimately reduce 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 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

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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.

A case in Pennsylvania has created uncertainty as to the application of long-standing legal precedent to title disputes involving natural gas produced from the Marcellus Shale formation, potentially exposing the Company to litigation.

When acquiring interests in properties in Pennsylvania from which the Company produces natural gas, the Company has relied upon a body of law developed by Pennsylvania courts over the course of more than 125 years. A long-standing rule of construction under Pennsylvania law known as the Dunham Rule creates a presumption that a deed, lease or other instrument that conveys, or reserves, minerals does not convey, or reserve, interests in natural gas or oil absent clear and convincing evidence that the parties to the conveyance contract intended to include oil and natural gas within the word minerals. A case in the intermediate appellate court in Pennsylvania (*Butler v. Estate of Powers*, Pa. Superior Ct., No. 1795 MDA 2010) creates uncertainty as to the application of the Dunham Rule in cases involving natural gas produced from the Marcellus Shale formation. Depending on the outcome of the ongoing litigation in *Butler*, the case could give rise to litigation as to whether, under the language of particular title documents and in consideration of the intent of the parties to particular conveyance contracts, rights to natural gas produced from the Marcellus Shale formation belong to the owner of the natural gas estate or the owner of the mineral estate. The Company believes that the Pennsylvania courts will ultimately confirm that the Dunham Rule applies to natural gas produced from the Marcellus Shale formation. If they were to hold otherwise, the Company could be involved in litigation to establish that the intent behind the conveyances to the Company of natural gas interests in Pennsylvania includes natural gas produced from the Marcellus Shale formation.

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.

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 have experienced such a change at the Canada/United States border at the Niagara River, where gas prices have increased relative to prices available at Leidy, Pennsylvania. This change in price differential has caused shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. Supply Corporation and Empire have seen transportation volumes decrease as a result of this situation, and in some cases, shippers have 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 have decreased, revenues and earnings in the Pipeline and Storage segment have decreased. Additional declines in this contracted transportation capacity could further adversely affect revenues, cash flows and results of operations. Supply Corporation and Empire are responding 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. The Company s Pipeline and Storage segment enters into hedging arrangements with respect to certain sales of efficiency gas.

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.

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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.

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. Similar restrictions apply in the Pipeline and Storage segment. 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 will not become effective until federal agencies (including the Commodity Futures Trading Commission (CFTC), various banking regulators and the SEC) adopt rules to implement the law. For purposes of the Dodd-Frank Act, we believe that the Company will be categorized as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge commercial risk. Nevertheless, the rules that are being developed could have a significant impact on the Company. For example, banking regulators have proposed a rule that would require swap dealers and major swap participants subject to their jurisdiction to collect initial and variation margin from counterparties that are non-financial end users, though such swap dealers and major swap participants would have the discretion to set thresholds for posting margin (unsecured credit limits). Regardless of the levels of margin that might be required, concern remains that swap dealers and major swap participants will pass along their increased capital and margin costs through higher prices and reductions in thresholds for posting margin. 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-cleared swap that is available as a cleared swap may be greater.

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 that became effective for the Company with its Form 10-K for the period ended September 30, 2010, 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 (under prior SEC requirements, the Company utilized market prices as of the last day of the period). 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 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

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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.

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 or discharge of contaminants and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. 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. Pursuant to an EPA determination, effective January 2011 projects proposing new stationary sources of significant greenhouse gas emissions or major modifications of existing facilities are required under the federal Clean Air Act to 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.

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 and monitoring of wells, the protection of water supplies, hydraulic fracturing of wells, surface owners rights and damage compensation, the spacing of wells, 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 could result in additional permitting, compliance, reporting and disclosure requirements. For example, the EPA has proposed regulations that would establish emission performance standards for hydraulic fracturing operations as well as natural gas gathering and transmission operations. If adopted, any such new state or federal legislation or regulation could lead to operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risks of litigation for the Company s Exploration and Production segment.

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.

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 $4 billion at September 30, 2011. Approximately 54% of this investment was in the Utility and Pipeline and Storage segments, whose operations are located primarily in western and central New York and northwestern Pennsylvania. The Exploration and Production segment, which has the next largest investment in net property, plant and equipment (44%), is primarily located in California and in the Appalachian region of the United States. The remaining net investment in property, plant and equipment consisted of the All Other and Corporate operations (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 $1.1 billion, or 39.0%, since 2006. 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. In addition, during 2007, the Company sold SECI, Seneca s wholly owned subsidiary that operated in Canada. The net property, plant and equipment of SECI at the date of sale was $107.7 million.

The Utility segment had a net investment in property, plant and equipment of $1.2 billion at September 30, 2011. The net investment in its gas distribution network (including 14,824 miles of distribution pipeline) and its service connections to customers represent approximately 50% and 34%, respectively, of the Utility segment s net investment in property, plant and equipment at September 30, 2011.

The Pipeline and Storage segment had a net investment of $954.6 million in property, plant and equipment at September 30, 2011. Transmission pipeline represents 36% of this segment s total net investment and includes 2,364 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 19% of this segment s total net investment and consist of 31 storage fields, four of which are jointly owned and operated with certain pipeline suppliers, and 431 miles of pipeline. Net investment in storage facilities includes $88.5 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 31 compressor stations with 101,559 installed compressor horsepower that represent 13% of this segment s total net investment in property, plant and equipment.

The Exploration and Production segment had a net investment in property, plant and equipment of $1.8 billion at September 30, 2011.

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The Utility and Pipeline and Storage segments   facilities provided the capacity to meet the Company   s 2011 peak day sendout, including transportation service, of 1,632 MMcf, which occurred on February 10, 2011. Withdrawals from storage of 646.4 MMcf provided approximately 39.6% 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 and in the Appalachian region of the United States. 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. Also, Exploration and Production operations were conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada, until the sale of those properties on August 31, 2007. Further discussion of oil and gas producing activities is included in Item 8, Note O   Supplementary Information for Oil and Gas Producing Activities. Note O sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2011 and 2010 reserves shown in Note O have been impacted by the SEC   s final rule on Modernization of Oil and Gas Reporting. The most notable change of the final rule includes the replacement of the single day period-end pricing used to value oil and gas reserves with 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.

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 eight 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 (with 13 years of experience in petroleum engineering and consulting at NSAI since 2004) and a professional geoscientist registered in the State of Texas (with 14 years of experience in petroleum geosciences and consulting at NSAI since 2008). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2011 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 openhole log data, performance data, log cross sections, core data, and statistical analysis. The statistical method utilized production performance from both the Company s and competitors wells. Geophysical data include data from the Company s wells, published documents, and state data-sites and were used to confirm continuity of the formation. Extension and discovery reserves added as a result of reliable technologies were not material.

Seneca s proved developed and undeveloped natural gas reserves increased from 428 Bcf at September 30, 2010 to 675 Bcf at September 30, 2011. This increase is attributed primarily to extensions and discoveries of 249.4 Bcf, primarily in the Appalachian region (249.0 Bcf), purchases of 44.8 Bcf in the Marcellus Shale in the Appalachian region, and positive revisions of previous estimates of 26.4 Bcf. This increase was partially offset by production of 50.5 Bcf and sales of minerals in place of 23.6 Bcf, primarily from the offshore Gulf of Mexico sale. Seneca s proved developed and undeveloped oil reserves decreased from 45,239 Mbbl at September 30, 2010 to 43,345 Mbbl at September 30, 2011. Extensions and discoveries of 767 Mbbl and positive revisions of previous estimates of 1,616 Mbbl were exceeded by production of 2,860 Mbbl, primarily occurring in the West Coast region (2,628 Mbbl) and sales of minerals in place of 1,417 Mbbl, primarily from the offshore Gulf of Mexico sale (979 Mbbl). On a Bcfe basis, Seneca s proved developed and undeveloped reserves increased from 700 Bcfe at September 30, 2010 to 935 Bcfe at September 30, 2011.

Seneca s proved developed and undeveloped natural gas reserves increased from 249 Bcf at September 30, 2009 to 428 Bcf at September 30, 2010. This increase is attributed primarily to extensions and discoveries (193.1 Bcf), primarily in the Appalachian region (190.0 Bcf), and revisions of previous estimates (16.7 Bcf). This increase was partially offset by production of 30.3 Bcf. Seneca s proved developed and undeveloped oil reserves decreased from 46,587 Mbbl at September 30, 2009 to 45,239 Mbbl at September 30, 2010. This decrease is attributed to production (3,220 Mbbl), primarily occurring in the West Coast region (2,669 Mbbl). This decrease was partly offset by extensions and discoveries (1,054 Mbbl) and revisions of previous estimates (818 Mbbl). On a Bcfe basis, Seneca s proved developed and undeveloped reserves increased from 528 Bcfe at September 30, 2009 to 700 Bcfe at September 30, 2010.

The Company s proved undeveloped (PUD) reserves increased from 177 Bcfe at September 30, 2010 to 295 Bcfe at September 30, 2011. PUD reserves in the Marcellus Shale increased from 110 Bcf at September 30, 2010 to 253 Bcf at September 30, 2011. There was a material increase in PUD reserves at September 30, 2011 and 2010 as a result of Marcellus Shale reserve additions. The Company s total PUD reserves are 32% of total proved reserves at September 30, 2011, up from 25% of total proved reserves at September 30, 2010.

The Company s PUD reserves increased from 87 Bcfe at September 30, 2009 to 177 Bcfe at September 30, 2010. PUD reserves in the Marcellus Shale increased from 11 Bcf at September 30, 2009 to 110 Bcf at September 30, 2010. There was a material increase in PUD reserves at September 30, 2010 as a result of Marcellus Shale reserve additions. The increase in PUD reserves in the Marcellus Shale is partially attributable to the change in SEC regulations allowing the recognition of PUD reserves more than one direct offset location away from existing production with reasonable certainty using reliable technology.

The increase in PUD reserves in 2011 of 118 Bcfe is a result of 212 Bcfe in new PUD reserve additions (209 Bcfe from the Marcellus Shale), offset by 83 Bcfe in PUD conversions to proved developed reserves, 10 Bcfe from sales of minerals in place and 2 Bcfe in downward PUD revisions of previous estimates. The downward revisions were primarily from the removal of proved locations in the Upper Devonian play. These locations are unlikely to be developed in the 5-year timeframe due to the Company s focus on the Marcellus Shale and the better economic results there. The Company invested $146 million during the year ended September 30, 2011 to convert 83 Bcfe of September 30, 2010 PUD reserves to proved developed reserves. The Company invested an additional $53 million during the year ended September 30, 2011 to develop the additional working interests in Covington area PUD wells that were acquired from EOG Resources during fiscal 2011. In 2012, the Company estimates that it will invest approximately $264 million to develop its PUD reserves. The Company is committed to developing its PUD reserves within five years as required by the

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SEC s final rule on Modernization of Oil and Gas Reporting. The Company developed 19% of its beginning year PUD reserves in fiscal 2010 and 47% of its beginning year PUD reserves in fiscal 2011.

The increase in PUD reserves in 2010 of 90 Bcfe is a result of 111 Bcfe in new PUD reserve additions (105 Bcfe from the Marcellus Shale), offset by 17 Bcfe in PUD conversions to proved developed reserves and 4 Bcfe in downward PUD revisions. The downward revisions were primarily from the removal of 51 PUD locations in the Upper Devonian play. This was the result of Seneca s decision in 2010 to significantly reduce its 5-year investment plan for the Upper Devonian as a result of lower forward gas price expectations. The Company invested $28.9 million during the year ended September 30, 2010 to convert 17 Bcfe of PUD reserves to proved developed reserves. This represented 19% of the PUD reserves booked at September 30, 2009.

At September 30, 2011, 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 or country level. All of the Company s proved reserves are in the United States. At the field level, only at the North Lost Hills Field in Kern County, California, does the Company have a material concentration of PUD reserves that have been on the books for more than five years. The Company has reduced the concentration of PUD reserves in this field from 61% of total field level proved reserves at September 30, 2005 to 20% of total field level proved reserves at September 30, 2011. The PUD reserves in this field represent less than 1% of the Company s proved reserves at the corporate level. The economics of this project remain strong and the steam-flood project here is performing well. Drilling of the remaining proved undeveloped locations in this field is scheduled over the next three years as steam generation capacity is increased and the steam-flood here matures.

At September 30, 2011, the Company had delivery commitments of 391Bcf. The Company expects to meet those commitments through proved reserves and the future development of reserves that are currently classified as proved undeveloped reserves and does not anticipate any issues or constraints that would prevent the Company from meeting these commitments.

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		
	2011	**2010**	**2009**
United States			
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 4.37(3)	$ 4.93(3)	$ 5.52
Average Sales Price per Barrel of Oil	$ 86.58	$ 75.81	$ 56.15
Average Sales Price per Mcf of Gas (after hedging)	$ 5.24	$ 6.15	$ 8.69
Average Sales Price per Barrel of Oil (after hedging)	$ 86.58	$ 75.81	$ 56.15
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.59(3)	$ 0.73(3)	$ 0.87
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	118(3)	45(3)	24
West Coast Region			
Average Sales Price per Mcf of Gas	$ 4.56	$ 4.81	$ 3.91
Average Sales Price per Barrel of Oil	$ 96.45	$ 71.72(2)	$ 50.90(2)
Average Sales Price per Mcf of Gas (after hedging)	$ 7.19	$ 7.02	$ 7.37
Average Sales Price per Barrel of Oil (after hedging)	$ 80.51	$ 74.88(2)	$ 67.61(2)
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 2.06	$ 1.71(2)	$ 1.38(2)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	53	54(2)	55(2)

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	For The Year Ended September 30 2011	2010	2009
Gulf Coast Region			
Average Sales Price per Mcf of Gas	$ 5.02	$ 5.22	$ 4.54
Average Sales Price per Barrel of Oil	$ 88.57	$ 76.57	$ 54.58
Average Sales Price per Mcf of Gas (after hedging)	$ 5.50	$ 5.51	$ 5.28
Average Sales Price per Barrel of Oil (after hedging)	$ 88.57	$ 77.18	$ 54.58
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.59	$ 1.15	$ 1.36
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	25(1)	37	38
Total Company			
Average Sales Price per Mcf of Gas	$ 4.43	$ 5.01	$ 4.79
Average Sales Price per Barrel of Oil	$ 95.78	$ 72.54	$ 51.69
Average Sales Price per Mcf of Gas (after hedging)	$ 5.39	$ 6.04	$ 6.94
Average Sales Price per Barrel of Oil (after hedging)	$ 81.13	$ 75.25	$ 64.94
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.08	$ 1.24	$ 1.27
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	185	136	116

(1) The Gulf Coast Region s offshore properties were sold in April 2011.

(2) The Midway Sunset North fields (which exceeded 15% of total reserves at 9/30/2010 and 9/30/2009) contributed 25 MMcfe and 28 MMcfe of production per day, at average sales prices (per bbl) of $69.68 ($75.75 after hedging), and $48.87 ($75.47 after hedging) for 2010 and 2009, respectively. Lifting costs (per Mcfe) were $1.90 and $1.34 for 2010 and 2009, respectively.

(3) The Marcellus Shale fields (which exceed 15% of total reserves at 9/30/2011 and 9/30/2010) contributed 97 MMcfe and 20 MMcfe of daily production in 2011 and 2010, respectively. The average sales price (per Mcfe) was $4.34 ($4.68 after hedging) in 2011 and $4.56 in 2010. The Company did not hedge Marcellus Shale production during 2010. The average lifting costs (per Mcfe) were $0.48 in 2011 and $0.55 in 2010.

Productive Wells

	Appalachian Region		West Coast Region		Total Company	
At September 30, 2011	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**
Productive Wells Gross	3,398	2		1,631	3,398	1,633
Productive Wells Net	2,907	2		1,596	2,907	1,598

Developed and Undeveloped Acreage

At September 30, 2011	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
Gross	523,985	14,100	538,085
Net	501,304	11,381	512,685
Undeveloped Acreage			
Gross	427,999	5,735	433,734
Net	409,376	886	410,262
Total Developed and Undeveloped Acreage			
Gross	951,984	19,835	971,819

Net	910,680	12,267	922,947

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As of September 30, 2011, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 5,104 acres in 2012 (2,928 net acres), 7,398 acres in 2013 (4,732 net acres), 3,174 acres in 2014 (2,119 net acres), and 69,769 acres thereafter (64,001 net acres). The remaining 348,289 gross acres (336,482 net acres) represent non-expiring oil and gas rights owned by the Company.

Drilling Activity

	Productive			Dry		
For the Year Ended September 30	**2011**	**2010**	**2009**	**2011**	**2010**	**2009**
United States						
Appalachian Region						
Net Wells Completed						
Exploratory	13.00	33.00	2.00		2.00	3.00
Development	48.76	131.55	250.00		3.00	
West Coast Region						
Net Wells Completed						
Exploratory	0.25					
Development	43.31	41.72	27.00			
Gulf Coast Region						
Net Wells Completed						
Exploratory		0.29	0.29			
Development	0.40					0.30
Total Company						
Net Wells Completed						
Exploratory	13.25	33.29	2.29		2.00	3.00
Development	92.47	173.27	277.00		3.00	0.30

Present Activities

At September 30, 2011	**Appalachian Region**	**West Coast Region**	**Total Company**
Wells in Process of Drilling(1)			
Gross	107.00		107.00
Net	73.50		73.50

(1) Includes wells awaiting completion.

Item 3 ***Legal Proceedings***

For a discussion of various environmental and other matters, refer to Part II, Item 7, MD&A and Item 8 at Note I Commitments and Contingencies. In addition to these matters, 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 quarterly and annual 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.

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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 N Market for Common Stock and Related Shareholder Matters (unaudited).

On July 1, 2011, the Company issued a total of 4,050 unregistered shares of Company common stock to the nine non-employee directors of the Company then serving on the Board of Directors of the Company, 450 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, 2011. These transactions were exempt from registration under Section 4(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, 2011	5,942	$ 70.41		6,971,019
Aug. 1-31, 2011	7,434	$ 56.75		6,971,019
Sept. 1-30, 2011	9,313	$ 56.33		6,971,019
Total	22,689	$ 60.15		6,971,019

(a) Represents (i) shares of common stock of the Company purchased on the open market with Company matching contributions for the accounts of participants in the Company s 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock options, SARs or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended September 30, 2011, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 22,689 shares purchased other than through a publicly announced share repurchase program, 20,707 were purchased for the Company s 401(k) plans and 1,982 were purchased as a result of shares tendered to the Company by holders of stock options, SARs or shares of restricted stock.

(b) In September 2008, the Company s Board of Directors authorized the repurchase of eight million shares of the Company s common stock. The Company, 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.

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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, 2006 through September 30, 2011. The graph assumes that the value of the investment in our common stock and in each index was $100 on September 30, 2006 and that all dividends were reinvested.

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.

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Item 6 ***Selected Financial Data***

	Year Ended September 30				
	2011	2010	2009	2008	2007
	(Thousands, except per share amounts and number of registered shareholders)				
Summary of Operations					
Operating Revenues	$ 1,778,842	$ 1,760,503	$ 2,051,543	$ 2,396,837	$ 2,034,400
Operating Expenses:					
Purchased Gas	628,732	658,432	997,216	1,238,405	1,019,349
Operation and Maintenance	400,519	394,569	401,200	429,394	395,704
Property, Franchise and Other Taxes	81,902	75,852	72,102	75,525	70,589
Depreciation, Depletion and Amortization	226,527	191,199	170,620	169,846	157,142
Impairment of Oil and Gas Producing Properties			182,811		
	1,337,680	1,320,052	1,823,949	1,913,170	1,642,784
Operating Income	441,162	440,451	227,594	483,667	391,616
Other Income (Expense):					
Income (Loss) from Unconsolidated Subsidiaries	(759)	2,488	3,366	6,303	4,979
Gain on Sale of Unconsolidated Subsidiaries	50,879				
Impairment of Investment in Partnership			(1,804)		
Other Income	6,706	3,638	8,200	7,164	6,995
Interest Income	2,916	3,729	5,776	10,815	1,550
Interest Expense on Long-Term Debt	(73,567)	(87,190)	(79,419)	(70,099)	(68,446)
Other Interest Expense	(4,554)	(6,756)	(7,370)	(3,271)	(4,155)
Income from Continuing Operations Before Income Taxes	422,783	356,360	156,343	434,579	332,539
Income Tax Expense	164,381	137,227	52,859	167,672	131,291
Income from Continuing Operations	258,402	219,133	103,484	266,907	201,248
Discontinued Operations:					
Income (Loss) from Operations, Net of Tax		470	(2,776)	1,821	15,906
Gain on Disposal, Net of Tax		6,310			120,301
Income (Loss) from Discontinued Operations, Net of Tax		6,780	(2,776)	1,821	136,207
Net Income Available for Common Stock	$ 258,402	$ 225,913	$ 100,708	$ 268,728	$ 337,455
Per Common Share Data					
Basic Earnings from Continuing Operations per Common Share	$ 3.13	$ 2.70	$ 1.29	$ 3.25	$ 2.42
Diluted Earnings from Continuing Operations per Common Share	$ 3.09	$ 2.65	$ 1.28	$ 3.16	$ 2.36
Basic Earnings per Common Share(1)	$ 3.13	$ 2.78	$ 1.26	$ 3.27	$ 4.06
Diluted Earnings per Common Share(1)	$ 3.09	$ 2.73	$ 1.25	$ 3.18	$ 3.96
Dividends Declared	$ 1.40	$ 1.36	$ 1.32	$ 1.27	$ 1.22
Dividends Paid	$ 1.39	$ 1.35	$ 1.31	$ 1.26	$ 1.21
Dividend Rate at Year-End	$ 1.42	$ 1.38	$ 1.34	$ 1.30	$ 1.24
At September 30:					
Number of Registered Shareholders	14,355	15,549	16,098	16,544	16,989

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