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

(716) 857-7000

Registrant s telephone number, including area code

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $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 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.

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.

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

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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.

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

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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.

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 open-

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hole 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

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

For the Year Ended September 30	Productive 2011	Productive 2010	Productive 2009	Dry 2011	Dry 2010	Dry 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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	Year Ended September 30				
	2011	2010	2009	2008	2007
	(Thousands, except per share amounts and number of registered shareholders)				
Net Property, Plant and Equipment					
Utility	$ 1,189,030	$ 1,165,240	$ 1,144,002	$ 1,125,859	$ 1,099,280
Pipeline and Storage	954,554	858,231	839,424	826,528	681,940
Exploration and Production	1,753,194	1,338,956	1,041,846	1,095,960	982,698
Energy Marketing	850	436	71	98	102
All Other(2)	97,228	81,103	101,104	98,338	106,637
Corporate	5,668	6,263	6,915	7,317	7,748
Total Net Plant	$ 4,000,524	$ 3,450,229	$ 3,133,362	$ 3,154,100	$ 2,878,405
Total Assets	$ 5,284,742	$ 5,105,625	$ 4,769,129	$ 4,130,187	$ 3,888,412
Capitalization					
Comprehensive Shareholders Equity	$ 1,891,885	$ 1,745,971	$ 1,589,236	$ 1,603,599	$ 1,630,119
Long-Term Debt, Net of Current Portion	899,000	1,049,000	1,249,000	999,000	799,000
Total Capitalization	$ 2,790,885	$ 2,794,971	$ 2,838,236	$ 2,602,599	$ 2,429,119

(1) Includes discontinued operations.

(2) Includes net plant of landfill gas discontinued operations as follows: $0 for 2011 and 2010, $9,296 for 2009, $11,870 for 2008 and $12,516 for 2007.

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

OVERVIEW

The Company is a diversified energy company and reports financial results for four business segments. Refer to Item 1, Business, for a more detailed description of each of the segments. This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, Results of Operations;
3. Operating, investing and financing cash flows under the heading Capital Resources and Liquidity;
4. Off-Balance Sheet Arrangements;
5. Contractual Obligations; and

6. Other Matters, including: (a) 2011 and projected 2012 funding for the Company s pension and other post-retirement benefits, (b) realizability of deferred tax assets, (c) disclosures and tables concerning market risk sensitive instruments, (d) rate and regulatory matters in the Company s New York, Pennsylvania and FERC regulated jurisdictions, (e) environmental matters, and (f) new authoritative accounting and financial reporting guidance.

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

For the year ended September 30, 2011 compared to the year ended September 30, 2010, the Company experienced an increase in earnings of $32.5 million. The earnings increase is primarily due to the recognition of a gain on the sale of unconsolidated subsidiaries of $50.9 million ($31.4 million after tax) during the quarter ended March 31, 2011 in the All Other category. In February 2011, the Company sold its 50% equity method investments in Seneca Energy and Model City for $59.4 million. Seneca Energy and

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Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. The sale is the result of the Company s strategy to pursue the sale of smaller, non-core assets in order to focus on its core businesses, including the development of the Marcellus Shale and the expansion of its pipeline business throughout the Appalachian region. For further discussion of the Company s earnings, refer to the Results of Operations section below.

The Marcellus Shale is 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. Due to the depth at which this formation is found, drilling and completion costs, including the drilling and completion of horizontal wells with hydraulic fracturing, are very expensive. However, independent geological studies have indicated that this formation could yield natural gas reserves measured in the trillions of cubic feet. The Company controls the natural gas interests associated with approximately 745,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations. The Company s reserve base has grown substantially from development in the Marcellus Shale. Natural gas proved developed and undeveloped reserves in the Appalachian region have increased from 331 Bcf at September 30, 2010 to 607 Bcf at September 30, 2011. With this in mind, and with a natural desire to realize the value of these assets in a responsible and orderly fashion, the Company has spent significant amounts of capital in this region. For the year ended September 30, 2011, the Company spent $585.1 million towards the development of the Marcellus Shale. This included paying $24.1 million in November 2010 for the acquisition of additional oil and gas properties in the Covington Township area of Tioga County, Pennsylvania from EOG Resources, Inc.

As the Company has been accelerating its Marcellus Shale development, it has been decreasing its emphasis in the Gulf Coast region. This culminated in the Company entering into a purchase and sale agreement in March 2011 to sell its off-shore oil and natural gas properties in the Gulf of Mexico effective as of January 1, 2011. The Company completed the sale in April 2011, receiving net proceeds of $55.4 million. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs in April 2011. The Company also eliminated the asset retirement obligation associated with its off-shore oil and gas properties. This obligation amounted to $37.5 million and was accounted for as a reduction of capitalized costs under the full cost method of accounting for oil and natural gas properties as well as a reduction of the asset retirement obligation. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

Coincident with the development of its Marcellus Shale acreage, the Company s Pipeline and Storage segment is building pipeline gathering and transmission facilities to connect Marcellus Shale production with existing pipelines in the region and is pursuing the development of additional pipeline and storage capacity in order to meet anticipated demand for the large amount of Marcellus Shale production expected to come on-line in the months and years to come. Two of the projects, the Tioga County Extension Project and the Northern Access expansion project, are considered significant for Empire and Supply Corporation. Both projects are designed to receive natural gas produced from the Marcellus Shale and transport it to Canada and the Northeast United States to meet growing demand in those areas. During the past two years, Empire and Supply Corporation have experienced a decline in the volumes of natural gas received at the Canada/United States border at the Niagara River to be shipped across their systems. The historical price advantage for gas sold at the Niagara import points has declined as production in the Canadian producing regions has declined or been diverted to other demand areas, and as production from new shale plays has increased in the United States. This factor has been causing shippers to seek alternative gas supplies and consequently alternative transportation routes. The Tioga County Extension Project and the Northern Access expansion project are designed to provide an alternative gas supply source for the customers of Empire and Supply Corporation. These projects, which are discussed more completely in the Investing Cash Flow section that follows, will involve significant capital expenditures.

From a capital resources perspective, the Company has largely been able to meet its capital expenditure needs for all of the above projects by using cash from operations. Looking forward, the Company expects to

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issue long-term debt in fiscal 2012 to help meet these needs. The Company also plans to increase its use of short-term debt as well.

The possibility of environmental risks associated with a well completion technology referred to as hydraulic fracturing continues to be debated. In Pennsylvania, where the Company is focusing its Marcellus Shale development efforts, the permitting and regulatory processes seem to strike a balance between the environmental concerns associated with hydraulic fracturing and the benefits of increased natural gas production. Hydraulic fracturing is a well stimulation technique that has been used for many years, and in the Company s experience, one that the Company believes has little negative impact to the environment. Nonetheless, the potential for increased state or federal regulation of hydraulic fracturing could impact future costs of drilling in the Marcellus Shale and lead to operational delays or restrictions. There is also the risk that drilling could be prohibited on certain acreage that is prospective for the Marcellus Shale. For example, New York State had a moratorium in place that prevented hydraulic fracturing of new horizontal wells in the Marcellus Shale. The moratorium ended in July 2011 and the DEC has issued its recommendations for shale development and production. However, the recommendations have not gone into effect to date. Due to the small amount of Marcellus Shale acreage owned by the Company in New York State, the final outcome of the DEC s recommendations are not expected to have a significant impact on the Company s plans for Marcellus Shale development. Please refer to the Risk Factors section above for further discussion.

CRITICAL ACCOUNTING ESTIMATES

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

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

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

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In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions to or subtractions from proved reserves and significant fluctuations in oil and gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. At September 30, 2011, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $366.1 million. The 12-month average of the first day of the month price for crude oil for each month during 2011, based on posted Midway Sunset prices, was $96.08 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2011, based on the quoted Henry Hub spot price for natural gas, was $4.16 per MMBtu. (Note Because actual pricing of the Company s various producing properties varies depending on their location and hedging, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for 2011.) If natural gas average prices used in the ceiling test calculation at September 30, 2011 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $197 million. If crude oil average prices used in the ceiling test calculation at September 30, 2011 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $321.4 million. If both natural gas and crude oil average prices used in the ceiling test calculation at September 30, 2011 were lower by $1 per MMBtu and $5 per Bbl, respectively, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $152.4 million. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation.

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

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

As discussed above, the full cost method of accounting provides a ceiling to the amount of costs that can be capitalized in the full cost pool. In accordance with current authoritative guidance, since the full cost pool includes an amount associated with plugging and abandoning the wells, as discussed in the preceding paragraph, the calculation of the full cost ceiling no longer reduces the future net cash flows from proved oil and gas reserves by an estimate of plugging and abandonment costs.

Regulation. The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to the FASB authoritative guidance regarding accounting for certain types of regulations, and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows the Company to defer expenses and income on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the ratesetting process in a period different from the period in which they would have been reflected in the income statement by an unregulated company. These deferred regulatory assets and liabilities are then flowed through the income statement in the period in which the same amounts are reflected in rates. Management s assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item. For further discussion of the Company s regulatory assets and liabilities, refer to Item 8 at Note C Regulatory Matters.

Accounting for Derivative Financial Instruments. The Company, in its Exploration and Production segment, Energy Marketing segment, and Pipeline and Storage segment, uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments are categorized as price swap agreements and futures contracts. In accordance with the authoritative guidance for derivative instruments and hedging activities, the Company accounted for these instruments as effective cash flow hedges or fair value hedges. Gains or losses associated with the derivative financial instruments are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that the derivative financial instruments would ever be deemed to be ineffective based on the effectiveness testing, mark-to-market gains or losses from the derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction.

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The Company adopted the authoritative guidance for fair value measurements during the quarter ended December 31, 2008. As such, the fair value of such derivative financial instruments is determined under the provisions of this guidance. The fair value of exchange traded derivative financial instruments is determined from Level 1 inputs, which are quoted prices in active markets. The Company determines the fair value of non exchange-traded derivative financial instruments based on an internal model, which uses both observable and unobservable inputs other than quoted prices. These inputs are considered Level 2 or Level 3 inputs. All derivative financial instrument assets and liabilities are evaluated for the probability of default by either the counterparty or the Company. Credit reserves are applied against the fair values of such assets or liabilities. Refer to the Market Risk Sensitive Instruments section below for further discussion of the Company s derivative financial instruments.

Pension and Other Post-Retirement Benefits. The amounts reported in the Company s financial statements related to its pension and other post-retirement benefits are determined on an actuarial basis, which uses many assumptions in the calculation of such amounts. These assumptions include the discount rate, the expected return on plan assets, the rate of compensation increase and, for other post-retirement benefits, the expected annual rate of increase in per capita cost of covered medical and prescription benefits. The Company utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year s anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the

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same anticipated benefit payments. The expected return on plan assets assumption used by the Company reflects the anticipated long-term rate of return on the plan s current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan s target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets. Changes in actuarial assumptions and actuarial experience, including deviations between actual versus expected return on plan assets, could have a material impact on the amount of pension and post-retirement benefit costs and funding requirements experienced by the Company. However, the Company expects to recover substantially all of its net periodic pension and other post-retirement benefit costs attributable to employees in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorization. For financial reporting purposes, the difference between the amounts of pension cost and post-retirement benefit cost recoverable in rates and the amounts of such costs as determined under applicable accounting principles is recorded as either a regulatory asset or liability, as appropriate, as discussed above under Regulation. Pension and post-retirement benefit costs for the Utility and Pipeline and Storage segments, as determined under the authoritative guidance for pensions and postretirement benefits, represented 91% and 93% of the Company s total pension and post-retirement benefit costs for the years ended September 30, 2011 and 2010, respectively.

Changes in actuarial assumptions and actuarial experience could also have an impact on the benefit obligation and the funded status related to the Company s pension and other post-retirement benefits and could impact the Company s equity. For example, the discount rate was changed from 4.75% in 2010 to 4.50% in 2011. The change in the discount rate from 2010 to 2011 increased the Retirement Plan projected benefit obligation by $26.9 million and the accumulated post-retirement benefit obligation by $14.5 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligation and the accumulated post-retirement benefit obligation. For 2011, the actual versus expected return on plan assets resulted in a decrease to the funded status of the Retirement Plan ($56.7 million) and the VEBA trusts and 401(h) accounts ($33.2 million). The actual versus expected benefit payments for 2011 caused a decrease of $2.4 million to the accumulated post-retirement benefit obligation. In calculating the projected benefit obligation for the Retirement Plan and the accumulated post-retirement obligation, the actuary takes into account the average remaining service life of active participants. The average remaining service life of active participants is 8 years for the Retirement Plan and 7 years for those eligible for other post-retirement benefits. For further discussion of the Company s pension and other post-retirement benefits, refer to Other Matters in this Item 7, which includes a discussion of funding for the current year, and to Item 8 at Note H Retirement Plan and Other Post Retirement Benefits.

RESULTS OF OPERATIONS

EARNINGS

2011 Compared with 2010

The Company s earnings were $258.4 million in 2011 compared with earnings of $225.9 million in 2010. The Company had earnings from discontinued operations of $6.8 million in 2010, as discussed below, but did not have any earnings from discontinued operations in 2011. Accordingly, the Company s earnings from continuing operations were $258.4 million in 2011 and $219.1 million in 2010. The increase in earnings from continuing operations of $39.3 million is primarily the result of higher earnings in the Exploration and Production segment and the All Other category. The Utility segment also contributed to the increase in earnings. Lower earnings in the Pipeline and Storage segment and a higher loss in the Corporate category slightly offset these increases. In the discussion that follows, note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted. Earnings from continuing operations and discontinued operations were impacted by the following events in 2011 and 2010:

2011 Event

A $50.9 million ($31.4 million after tax) gain on the sale of unconsolidated subsidiaries as a result of the Company s sale of its 50% equity method investments in Seneca Energy and Model City.

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2010 Event

A $6.3 million gain on the sale of the Company s landfill gas operations, which was completed in September 2010. This amount is included in earnings from discontinued operations.

2010 Compared with 2009

The Company s earnings were $225.9 million in 2010 compared with earnings of $100.7 million in 2009. The Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana in September 2010. Accordingly, all financial results for those operations, which are part of the All Other category, have been presented as discontinued operations. The Company s earnings from continuing operations were $219.1 million in 2010 compared with $103.5 million in 2009. The Company s earnings from discontinued operations were $6.8 million in 2010 compared to a loss of $2.8 million in 2009. The increase in earnings from continuing operations of $115.6 million is primarily the result of higher earnings in the Exploration and Production segment. The Utility and Energy Marketing segments, as well as the All Other category, also contributed to the increase in earnings. Lower earnings in the Pipeline and Storage segment and a higher loss in the Corporate category slightly offset these increases. The increase in earnings from discontinued operations primarily resulted from the gain on the sale of the Company s landfill gas operations recognized in 2010 as well as the non-recurrence of $2.8 million of impairment charges recognized in 2009 related to certain landfill gas assets. Earnings from continuing operations and discontinued operations were impacted by the 2010 event discussed above and several events in 2009, including:

2009 Events

A non-cash $182.8 million impairment charge ($108.2 million after tax) recorded during the quarter ended December 31, 2008 for the Exploration and Production segment s oil and gas producing properties;

A $2.8 million impairment in the value of certain landfill gas assets;

A $1.1 million impairment in the value of the Company s 50% investment in ESNE (recorded in the All Other category), a limited liability company that owns an 80-megawatt, combined cycle, natural gas-fired power plant in the town of North East, Pennsylvania; and

A $2.3 million death benefit gain on life insurance policies recognized in the Corporate category.

Earnings (Loss) by Segment

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
Utility	$ 63,228	$ 62,473	$ 58,664
Pipeline and Storage	31,515	36,703	47,358
Exploration and Production	124,189	112,531	(10,238)
Energy Marketing	8,801	8,816	7,166
Total Reported Segments	227,733	220,523	102,950
All Other	38,502	3,396	705
Corporate	(7,833)	(4,786)	(171)
Total Earnings from Continuing Operations	258,402	219,133	103,484

Earnings (Loss) from Discontinued Operations		6,780	(2,776)
Total Consolidated	$ 258,402	$ 225,913	$ 100,708

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UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30 2011	2010 (Thousands)	2009
Retail Revenues:			
Residential	$ 603,838	$ 583,443	$ 850,088
Commercial	80,811	81,110	128,520
Industrial	5,849	5,697	7,213
	690,498	670,250	985,821
Off-System Sales	33,968	29,135	3,740
Transportation	123,729	109,675	111,483
Other	4,300	10,730	11,980
	$ 852,495	$ 819,790	$ 1,113,024

Utility Throughput million cubic feet (MMcf)

	Year Ended September 30 2011	2010	2009
Retail Sales:			
Residential	57,466	54,012	58,835
Commercial	8,517	8,203	9,551
Industrial	723	646	515
	66,706	62,861	68,901
Off-System Sales	7,151	5,899	513
Transportation	66,273	60,105	59,751
	140,130	128,865	129,165

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Prior Year
2011(1):	Buffalo	6,692	6,751	0.9%	7.3%
	Erie	6,243	6,359	1.9%	6.9%
2010(2):	Buffalo	6,692	6,292	(6.0)%	(6.1)%
	Erie	6,243	5,947	(4.7)%	(3.7)%
2009(3):	Buffalo	6,692	6,701	0.1%	6.8%
	Erie	6,243	6,176	(1.1)%	6.9%

(1) Percents compare actual 2011 degree days to normal degree days and actual 2011 degree days to actual 2010 degree days.

(2) Percents compare actual 2010 degree days to normal degree days and actual 2010 degree days to actual 2009 degree days.

(3) Percents compare actual 2009 degree days to normal degree days and actual 2009 degree days to actual 2008 degree days.

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2011 Compared with 2010

Operating revenues for the Utility segment increased $32.7 million in 2011 compared with 2010. This increase largely resulted from a $20.2 million increase in retail gas sales revenues, a $14.1 million increase in transportation revenues, and a $4.8 million increase in off-system sales revenue. These were partially offset by a $6.4 million decrease in other operating revenues.

The increase in retail gas sales revenues of $20.2 million was largely a function of higher volumes (3.8 Bcf) due to colder weather and higher customer usage per account. The increase in volumes resulted in the recovery of a larger amount of gas costs, despite a decline in the Utility segment s average cost of purchased gas. Subject to certain timing variations, gas costs are recovered dollar for dollar in revenues. See further discussion of purchased gas below under the heading Purchased Gas. The increase in transportation revenues of $14.1 million was primarily due to a 6.2 Bcf increase in transportation throughput, largely the result of colder weather and the migration of customers from retail sales to transportation service. The increase in off-system sales revenues was largely due to an increase in off-system sales volume. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins. The $6.4 million decrease in other operating revenues was largely attributable to an adjustment to the carrying value of certain regulatory asset accounts to a level the Company believes will ultimately be recovered in the rate-setting process.

2010 Compared with 2009

Operating revenues for the Utility segment decreased $293.2 million in 2010 compared with 2009. This decrease largely resulted from a $315.6 million decrease in retail gas sales revenues, a $1.8 million decrease in transportation revenues, and a $1.2 million decrease in other operating revenues. These were partially offset by a $25.4 million increase in off-system sales revenue.

The decrease in retail gas sales revenues of $315.6 million was largely a function of warmer weather and lower gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues). The recovery of lower gas costs resulted from a lower cost of purchased gas combined with the refunding of previously over-recovered purchased gas costs. See further discussion of purchased gas below under the heading Purchased Gas.

The increase in off-system sales revenues of $25.4 million was largely due to the Utility segment not engaging in off-system sales from November 2008 through October 2009. This was due to Order No. 717 (Final Rule), which was issued by the FERC on October 16, 2008. The Final Rule seemingly held that a local distribution company making off-system sales on unaffiliated pipelines would be engaging in marketing that would require Distribution Corporation to substantially modify its operations in order to assure compliance with the FERC s standards of conduct. Accordingly, pending clarification of this issue from the FERC, as of November 1, 2008, Distribution Corporation ceased off-system sales activities. On October 15, 2009, the FERC released Order No. 717-A, which clarified that a local distribution company making off-system sales of gas that has been transported on non-affiliated pipelines is not subject to the FERC standards of conduct. In light of and in reliance on this clarification, Distribution Corporation determined that it could resume engaging in off-system sales on non-affiliated pipelines. Such off-system sales resumed in November 2009. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to earnings.

The decrease in transportation revenues of $1.8 million was primarily due to warmer weather and the resulting decrease in transportation volumes for residential and commercial customers. While there was a slight increase in transportation volumes of 0.4 Bcf for all revenue classes, this was largely due to an increase in throughput for large industrial customers. Throughput variations associated with large industrial customers do not have a significant impact on transportation revenues. The decrease in other operating revenues of $1.2 million is largely due to a decrease in late payment revenue, caused by a decrease in gas costs.

Purchased Gas

The cost of purchased gas is the Company s single largest operating expense. Annual variations in purchased gas costs are attributed directly to changes in gas sales volumes, the price of gas purchased and the operation of purchased gas adjustment clauses. Distribution Corporation recorded $460.1 million, $428.4 million and $713.2 million of Purchased Gas Expense during 2011, 2010 and 2009, respectively. Under its purchased gas adjustment clauses in New York and Pennsylvania, Distribution Corporation is not allowed to profit from fluctuations in gas costs. Purchased gas expense recorded on the consolidated income statement matches the revenues collected from customers, a component of Operating Revenues on the consolidated income statement. Under mechanisms approved by the NYPSC in New York and the PaPUC in Pennsylvania, any difference between actual purchased gas costs and what has been collected from the customer is deferred on the consolidated balance sheet as either an asset, Unrecovered Purchased Gas Costs, or a liability, Amounts Payable to Customers. These deferrals are subsequently collected from the customer or passed back to the customer, subject to review by the NYPSC and the PaPUC. Absent disallowance of full recovery of Distribution Corporation s purchased gas costs, such costs do not impact the profitability of the Company. Purchased gas costs impact cash flow from operations due to the timing of recovery of such costs versus the actual purchased gas costs incurred during a particular period. Distribution Corporation s purchased gas adjustment clauses seek to mitigate this impact by adjusting revenues on either a quarterly or monthly basis.

Currently, Distribution Corporation has contracted for long-term firm transportation capacity with Supply Corporation, Empire and seven other upstream pipeline companies, for long-term gas supplies with a combination of producers and marketers, and for storage service with Supply Corporation and two nonaffiliated companies. In addition, Distribution Corporation satisfies a portion of its gas requirements through spot market purchases. Changes in wellhead prices have a direct impact on the cost of purchased gas. Distribution Corporation s average cost of purchased gas, including the cost of transportation and storage, was $6.41 per Mcf in 2011, a decrease of 10% from the average cost of $7.13 per Mcf in 2010. The average cost of purchased gas in 2010 was 13% lower than the average cost of $8.17 per Mcf in 2009. Additional discussion of the Utility segment s gas purchases appears under the heading Sources and Availability of Raw Materials in Item 1.

Earnings

2011 Compared with 2010

The Utility segment s earnings in 2011 were $63.2 million, an increase of $0.7 million when compared with earnings of $62.5 million in 2010. The increase in earnings is largely attributable to colder weather ($2.4 million) and higher usage per account ($1.9 million) in Pennsylvania. The phrase usage per account refers to average gas consumption per account after factoring out any impact that weather may have had on consumption. In addition, earnings were positively impacted by lower interest expense on deferred gas costs ($1.0 million) and lower operating expenses ($1.6 million) due to decreased bad debt expense and personnel costs partially offset by higher pension expense. These increases were partially offset by various regulatory adjustments ($3.7 million), primarily due to an adjustment to the carrying value of certain regulatory asset accounts to a level the Company believes will ultimately be recovered in the rate-setting process, an increase in other taxes ($0.9 million), higher income tax expense ($0.7 million) and higher depreciation expense ($0.3 million.)

The impact of weather on the Utility segment s New York rate jurisdiction is tempered by a weather normalization clause (WNC). The WNC, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment s New York customers. For 2011, the WNC reduced earnings by approximately $1.0 million, as the weather was colder than normal. For 2010, the WNC preserved earnings of approximately $1.3 million, as the weather was warmer than normal.

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2010 Compared with 2009

The Utility segment s earnings in 2010 were $62.5 million, an increase of $3.8 million when compared with earnings of $58.7 million in 2009. The increase in earnings was primarily due to the positive earnings impact associated with a lower effective tax rate ($4.8 million), lower operating expenses ($4.3 million) and routine regulatory adjustments ($1.2 million). The effective tax rate impact is attributable to a lower state income tax expense in 2010 as a result of the pass-back to customers of over-collected gas costs.

The decrease in operating expenses was mainly due to a decrease in bad debt expense slightly offset by an increase in personnel costs. These factors were partially offset by lower usage per account in Pennsylvania ($2.1 million), higher interest expense ($2.1 million), lower late payment revenue due to lower gas costs ($1.2 million) and warmer weather in Pennsylvania ($0.8 million). The increase in interest expense was partially due to the Company s April 2009 debt issuance that was issued at a significantly higher interest rate than the debt that had matured in March 2009. In addition, accrued interest on deferred gas costs increased as a result of the over-recovery of gas costs during fiscal 2009.

For 2010, the WNC preserved earnings of approximately $1.3 million, as the weather was warmer than normal. For 2009, the WNC reduced earnings by approximately $0.2 million, as the weather was colder than normal.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
Firm Transportation	$ 134,652	$ 139,324	$ 139,034
Interruptible Transportation	1,341	1,863	3,175
	135,993	141,187	142,209
Firm Storage Service	66,712	66,593	66,711
Interruptible Storage Service	19	78	20
	66,731	66,671	66,731
Other	12,384	11,025	10,333
	$ 215,108	$ 218,883	$ 219,273

Pipeline and Storage Throughput (MMcf)

	Year Ended September 30		
	2011	2010	2009
Firm Transportation	317,917	296,907	348,294
Interruptible Transportation	2,037	4,459	3,888
	319,954	301,366	352,182

2011 Compared with 2010

Operating revenues for the Pipeline and Storage segment decreased $3.8 million in 2011 as compared with 2010. The decrease was primarily due to a decrease in transportation revenues of $5.2 million. The decrease in transportation revenues was primarily the result of a reduction in the level of contracts entered into by shippers year over year as shippers utilized lower priced pipeline transportation routes. Shippers continue to seek alternative lower priced gas supply (and in some cases, do not renew short-term transportation contracts) because of the relatively higher price of natural gas supplies available at the United States/Canadian border at the Niagara River near Buffalo, New York compared to the lower pricing for supplies available at Leidy, Pennsylvania. Empire s Tioga County Extension Project and Supply Corporation s Northern Access expansion project, both of which are discussed in the Investing Cash Flow section that follows, are designed to utilize that available pipeline capacity by receiving natural gas produced from the Marcellus Shale and transporting it to Canada and the Northeast United States where demand has been growing. The decrease was partially offset by an increase in efficiency gas revenues of $1.0 million (reported as a part of other revenue in the table above) due to higher efficiency gas volumes partially offset by lower gas prices. Under Supply Corporation s tariff with shippers, Supply Corporation is allowed to retain a set percentage of shipper-supplied gas as compressor fuel and for other operational purposes. To the extent that Supply Corporation does not need all of the gas to cover such operational needs, it is allowed to keep the excess gas as inventory. That inventory is later sold to buyers on the open market. The excess gas that is retained as inventory, as well as any gains resulting from the sale of such inventory, represent efficiency gas revenue to Supply Corporation. Also offsetting the decrease in revenues was an increase in cashout revenues of $0.3 million (reported as a part of other revenue in the table above). Cashout revenues are completely offset by purchased gas expense and as a result have no impact on earnings.

Volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire, but this rate design does not protect Supply Corporation or Empire in situations where shippers do not contract for that capacity at the same quantity and rate. In that situation, Supply Corporation or Empire can propose revised rates and services in a rate case at the FERC. Transportation volume increased by 18.6 Bcf in 2011 as compared with 2010. While transportation volume increased largely due to colder weather, there was little impact on revenues due to the straight fixed-variable rate design.

2010 Compared with 2009

Operating revenues for the Pipeline and Storage segment decreased $0.4 million in 2010 as compared with 2009. The decrease was due to a decrease in interruptible transportation revenues of $1.3 million largely due to a decrease in the gathering rate under Supply Corporation s tariff. Also contributing to the decrease was a decrease in cashout revenues of $0.3 million. Offsetting the decrease was an increase in efficiency gas revenues of $1.3 million due to higher efficiency gas volumes and a significantly lower efficiency gas inventory write down in 2010 versus 2009. These increases to efficiency gas revenues were partially offset by lower gas prices and a lower gain, period over period, on the sale of retained efficiency gas volumes held in inventory. Also offsetting the decrease in revenues was an increase in firm transportation revenues of $0.3 million. This increase was primarily the result of higher revenues from the Empire Connector, which was placed in service in December 2008, partially offset by a reduction in the level of short-term contracts entered into by shippers period over period as such shippers utilized lower priced pipeline transportation routes.

Transportation volume decreased by 50.8 Bcf in 2010 as compared with 2009. These decreases were largely due to shippers seeking alternative lower priced gas supply (and in some cases, not renewing short-term transportation contracts) combined with warmer weather and lower industrial demand. As discussed above, volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design.

Earnings

2011 Compared with 2010

The Pipeline and Storage segment s earnings in 2011 were $31.5 million, a decrease of $5.2 million when compared with earnings of $36.7 million in 2010. The decrease in earnings is primarily due to the earnings impact of higher operating expenses ($3.2 million), lower transportation revenues of $3.4 million, as discussed above, higher depreciation expense ($0.9 million) and higher property taxes ($0.3 million). The increase in operating expenses can be attributed primarily to higher pension expense ($1.4 million), higher compressor maintenance costs ($0.7 million), higher personnel costs ($0.6 million) and the write-off of expired and unused storage rights ($0.6 million). The increase in property taxes is primarily a result of a higher tax base due to capital additions combined with higher Pennsylvania public utility realty taxes. The increase in depreciation expense is primarily the result of a revision during fiscal 2011 to correct accumulated depreciation as well as additional projects that were placed in service in the last year. These earnings decreases were partially offset by an increase in the allowance for funds used during construction (equity component) of $2.0 million primarily due to construction commencing during the current year on Supply Corporation s Line N Expansion Project and Lamont Phase II Project and Empire s Tioga County Extension Project, as discussed in the Investing Cash Flow section that follows, and by the earnings impact associated with higher efficiency gas revenues ($0.7 million), as discussed above.

2010 Compared with 2009

The Pipeline and Storage segment s earnings in 2010 were $36.7 million, a decrease of $10.7 million when compared with earnings of $47.4 million in 2009. The decrease in earnings is primarily due to a decrease in the allowance for funds used during construction ($2.3 million), higher operating costs ($4.5 million), higher property taxes ($2.0 million), higher interest expense ($3.1 million) and higher depreciation expense ($0.5 million). Lower transportation revenues of $0.7 million, as discussed above, also contributed to the earnings decrease. The decrease in allowance for funds used during construction (equity component) is a result of the construction of the Empire Connector, which was completed and placed in service on December 10, 2008. The increase in operating expenses can primarily be attributed to higher pension expense, higher personnel costs, and an increase in corrosion logging expenses associated with Supply Corporation s storage wells. The increase in property taxes is primarily a result of additional property taxes and higher payments in lieu of taxes associated with the Empire Connector. The increase in interest expense can be attributed to higher debt balances and a higher average interest rate on borrowings combined with a decrease in the allowance for borrowed funds used during construction resulting from the completion of the Empire Connector. The increase in the average interest rate stems from the Company s April 2009 debt issuance. The increase in depreciation expense is primarily the result of the Empire Connector being placed in service in December 2008. These earnings decreases were partially offset by the earnings impact associated with higher efficiency gas revenues ($0.8 million), as discussed above, and lower income tax expense ($1.4 million) due to a lower effective tax rate.

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
Gas (after Hedging)	$ 272,057	$ 183,327	$ 154,582
Oil (after Hedging)	232,052	242,303	219,046
Gas Processing Plant	28,711	29,369	24,686
Other	513	820	432
Intrasegment Elimination(1)	(14,298)	(17,791)	(15,988)
Operating Revenues	$ 519,035	$ 438,028	$ 382,758

(1) Represents the elimination of certain West Coast gas production revenue included in Gas (after Hedging) in the table above that is sold to the gas processing plant shown in the table above. An elimination for the same dollar amount was made to reduce the gas processing plant s Purchased Gas expense.

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Production

	Year Ended September 30		
	2011	2010	2009
Gas Production ***(MMcf)***			
Gulf Coast	4,041	10,304	9,886
West Coast	3,447	3,819	4,063
Appalachia	42,979	16,222	8,335
Total Production	50,467	30,345	22,284
Oil Production ***(Mbbl)***			
Gulf Coast	187	502	640
West Coast	2,627	2,669	2,674
Appalachia	46	49	59
Total Production	2,860	3,220	3,373

Average Prices

	Year Ended September 30		
	2011	2010	2009
Average Gas Price/Mcf			
Gulf Coast	$ 5.02	$ 5.22	$ 4.54
West Coast	$ 4.56	$ 4.81	$ 3.91
Appalachia	$ 4.37	$ 4.93	$ 5.52
Weighted Average	$ 4.43	$ 5.01	$ 4.79
Weighted Average After Hedging(1)	$ 5.39	$ 6.04	$ 6.94
Average Oil Price/Barrel (bbl)			
Gulf Coast	$ 88.57	$ 76.57	$ 54.58
West Coast	$ 96.45	$ 71.72	$ 50.90
Appalachia	$ 86.58	$ 75.81	$ 56.15
Weighted Average	$ 95.78	$ 72.54	$ 51.69
Weighted Average After Hedging(1)	$ 81.13	$ 75.25	$ 64.94

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

2011 Compared with 2010

Operating revenues for the Exploration and Production segment increased $81.0 million in 2011 as compared with 2010. Gas production revenue after hedging increased $88.7 million primarily due to production increases in the Appalachian division, partially offset by decreases in Gulf Coast production. The increase in Appalachian production was primarily due to additional wells within the Marcellus Shale formation, primarily in Tioga County, Pennsylvania, coming on line in fiscal 2011. The decrease in Gulf Coast gas production resulted from the sale of the Exploration and Production segment s off-shore oil and natural gas properties in April 2011. Increases in natural gas production were partially offset by a $0.65 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging decreased $10.3 million due to a decrease in production as a result of the aforementioned sale of Gulf Coast off-shore properties. This decrease in oil production revenue was partially offset by an increase in the weighted average price of oil after hedging ($5.88 per Bbl). In addition, there was a $2.8 million increase in gas processing plant revenues (net of eliminations) primarily due to the lower cost of West Coast residual and liquids production in 2011 versus 2010.

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

2010 Compared with 2009

Operating revenues for the Exploration and Production segment increased $55.3 million in 2010 as compared with 2009. Gas production revenue after hedging increased $28.7 million primarily due to production increases in the Appalachian division. The increase in Appalachian natural gas production was mainly due to Marcellus Shale production that came on line during fiscal 2010, primarily in Tioga County, Pennsylvania. Increases in natural gas production were partially offset by a $0.90 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging increased $23.3 million due to an increase in the weighted average price of oil after hedging ($10.31 per Bbl), while oil production levels were slightly lower in fiscal 2010. In addition, there was a $2.9 million increase in gross processing plant revenues (net of eliminations) due to an increase in the commodity prices of residual gas and liquids sold at Seneca s processing plants in the West Coast region.

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

Earnings

2011 Compared with 2010

The Exploration and Production segment s earnings for 2011 were $124.2 million, compared with earnings of $112.5 million for 2010, an increase of $11.7 million. Higher natural gas production and higher crude oil prices increased earnings by $79.0 million and $10.9 million, respectively. Higher processing plant revenues ($1.8 million) further contributed to an increase in earnings. Lower interest expense ($8.4 million) due to a lower average amount of debt further contributed to an increase in earnings. Lower natural gas prices ($21.3 million) and lower crude oil production ($17.6 million) partially offset the increase in earnings. In addition, earnings were further reduced by higher depletion expense ($26.4 million), higher general, administrative and other operating expenses ($11.4 million), higher lease operating expenses ($7.7 million), higher income tax expense ($2.5 million), and higher property and other taxes ($1.0 million). The increase in depletion expense is primarily due to an increase in production and depletable base (largely due to increased capital spending in the Appalachian region, specifically related to the development of Marcellus Shale properties). The increase in lease operating expenses is largely attributable to a higher number of producing properties in Appalachia. Higher personnel costs are largely responsible for the increase in general, administrative and other operating expenses. Higher property and other taxes are attributable to a revision of the California property tax liability, which was partially offset by a decrease in property and other taxes as a result of the sale of the Gulf Coast s off-shore properties in April 2011. The increase in income tax expense is attributable to higher state income taxes coupled with the loss of a domestic production activities deduction that occurred during the quarter ended September 30, 2010 and its impact on the effective tax rate during fiscal 2011. The decrease in interest and other income is largely attributable to lower cash investment balances in 2011 as compared to 2010.

2010 Compared with 2009

The Exploration and Production segment s earnings for 2010 were $112.5 million, compared with a loss of $10.2 million for 2009, an increase of $122.7 million. The increase in earnings is primarily the result of the non-recurrence of an impairment charge of $108.2 million during the quarter ended December 31, 2008, as discussed above. Higher natural gas production and higher crude oil prices increased earnings by $36.3 million and $21.6 million, respectively. Higher processing plant revenues ($1.9 million) largely due to an increase in commodity prices of residual gas and liquids sold at Seneca s processing plants in the West Coast region further contributed to an increase in earnings. Lower interest expense ($1.6 million) due to a lower average amount of debt outstanding and the capitalization of interest further contributed to an increase in earnings. In addition, lower general and administrative and other operating expenses ($1.2 million) increased earnings. The decrease in general and administrative and other operating expenses primarily reflects variations between actual plugging and abandonment costs incurred versus amounts previously accrued for such properties. During 2010, actual plugging and abandonment costs incurred were less than the liability that had been established for such properties, resulting in a gain. The decrease in general and administrative and other operating expenses also reflects a decrease in bad debt expense. Higher personnel costs, primarily in the Appalachian region, partially offset these decreases. Lower natural gas prices ($17.7 million) and lower crude oil production ($6.5 million) partially offset the increase in earnings. In addition, the earnings increases noted above were partially offset by higher depletion expense ($10.0 million), the earnings impact associated with higher income tax expense ($7.2 million), higher lease operating expenses ($6.1 million), and lower interest income ($0.9 million). The increase in depletion expense was primarily due to an increase in production and depletable base (largely due to increased capital spending in the Appalachian region). The increase in income tax expense in 2010 is attributable to the loss of a domestic production activities deduction for fiscal 2010, the non-recurrence of a Corporate tax benefit received in the prior year, and higher state income taxes. Lease operating expenses increased due to higher steaming costs in California, additional production properties related to the acquisition of Ivanhoe Energy s United States oil and gas properties in July 2009, an increase in the costs associated with a higher number of producing properties in the Appalachian region, primarily within the Marcellus Shale, and higher production taxes. The reduction in interest income was largely due to lower interest rates on cash investment balances.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2011	**2010**	**2009**
		(Thousands)	
Natural Gas (after Hedging)	$ 284,916	$ 344,077	$ 398,205
Other	50	725	116
	$ 284,966	$ 344,802	$ 398,321

Energy Marketing Volume

	Year Ended September 30		
	2011	**2010**	**2009**
Natural Gas (MMcf)	52,893	58,299	60,858

2011 Compared with 2010

Operating revenues for the Energy Marketing segment decreased $59.8 million in 2011 as compared with 2010. The decrease primarily reflects a decline in gas sales revenue due largely to a decrease in volume sold as well as a lower average price of natural gas that was recovered through revenues. The decrease in volume is largely attributable to the non-recurrence of sales transactions undertaken at the Niagara pipeline delivery point to offset certain basis risks that the Energy Marketing segment was exposed to under certain fixed basis commodity purchase contracts for Appalachian production. The decrease in volume also reflects a decrease in volume sold to low-margin wholesale customers. Such transactions had the effect of increasing revenue and volume sold with minimal impact to earnings. The decrease in volume sold to wholesale customers was partially offset by an increase in volume sold to retail customers.

2010 Compared with 2009

Operating revenues for the Energy Marketing segment decreased $53.5 million in 2010 as compared with 2009. The decrease primarily reflects a decline in gas sales revenue due to a lower average price of

natural gas that was recovered through revenues, as well as a decrease in volume sold. The decrease in volume is largely attributable to a decrease in volume sold to low-margin wholesale customers as well as fewer sales transactions undertaken at the Niagara pipeline delivery point to offset certain basis risks that the Energy Marketing segment was exposed to under certain fixed basis commodity purchase contracts for Appalachian production. Such transactions had the effect of increasing revenue and volume sold with minimal impact to earnings.

Earnings

2011 Compared with 2010

The Energy Marketing segment s earnings were $8.8 million in both 2011 and 2010. A decrease in margin of $0.3 million was offset by the positive impact of lower income tax expense ($0.2 million) and lower operating costs ($0.1 million). The decrease in margin was due to a lower benefit that the Energy Marketing segment derived from its contracts for storage capacity and the non-recurrence of proceeds received in 2010 as a member of a class of claimants in a class action litigation settlement, offset somewhat by higher volume sold to retail customers.

2010 Compared with 2009

The Energy Marketing segment s earnings in 2010 were $8.8 million, an increase of $1.6 million when compared with earnings of $7.2 million in 2009. This increase was primarily attributable to higher margin of $1.4 million combined with lower income tax expense of $0.4 million. The increase in margin was primarily driven by improved average margins per Mcf, the benefit that the Energy Marketing segment derived from its contracts for storage capacity, and proceeds received as a member of a class of claimants in a class action litigation settlement. Higher operating costs of $0.1 million slightly offset the increase in earnings. The increase in operating expenses was primarily due to a June 2010 accrual for U.S. Customs merchandise processing fees that may be due for certain past gas imports from Canada, largely offset by lower bad debt expense.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of Seneca s Northeast Division, Highland (which was merged into Seneca s Northeast Division in June 2011), Midstream Corporation, Horizon Power and corporate operations. Seneca s Northeast Division markets timber from its New York and Pennsylvania land holdings. In September 2010, the Company sold its sawmill in Marienville, Pennsylvania along with the mill s inventory, stumpage tracts and certain land and timber acreage for approximately $15.8 million. The Company recognized a gain of approximately $0.4 million from this sale ($0.2 million after tax). The Company continues to maintain a forestry operation, but will no longer be processing lumber products. Midstream Corporation is a Pennsylvania corporation formed to build, own and operate natural gas processing and pipeline gathering facilities in the Appalachian region. Horizon Power s current activity primarily consists of a 50% equity method investment in ESNE. On November 1, 2010, ESNE stopped all electricity generation operations. The turbines and other assets are in the process of being sold and/or dismantled. ESNE generated electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. In February 2011, Horizon Power sold its 50% equity method investments in Seneca Energy and Model City for $59.4 million. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. The sale is the result of the Company s strategy to pursue the sale of smaller, non-core assets in order to focus on its core businesses, including the development of the Marcellus Shale and the expansion of its pipeline business throughout the Appalachian region. The Company reports income from its equity method investments as Income from Unconsolidated Subsidiaries on the Consolidated Statements of Income. In September 2010, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana for $38.0 million, recognizing a gain of $10.3 million ($6.3 million after tax). The Company s landfill gas operations were maintained under the Company s wholly owned subsidiary, Horizon LFG, which owned

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and operated these short distance landfill gas pipeline companies. These operations are presented in the Company s financial statements as discontinued operations. Refer to Item 8 at Note J Discontinued Operations for further details.

Earnings

2011 Compared with 2010

All Other and Corporate operations had income from continuing operations of $30.7 million in 2011 compared with a loss from continuing operations of $1.4 million in 2010. The overall increase in earnings from continuing operations is due to the gain on the sale of Horizon Power s investments in Seneca Energy and Model City of $31.4 million, lower interest expense of $8.4 million (primarily the result of lower borrowings at a lower interest rate due to the repayment of $200 million of 7.5% notes that matured in November 2010), higher gathering and processing revenues of $5.1 million (due to an increase in Midstream Corporation s gathering and processing revenues) and lower depreciation and depletion expense of $4.6 million (due to a decrease in timber harvested as a result of the sale of the Company s timber harvesting and milling operations in September 2010). Lower income tax expense ($0.8 million) further contributed to the earnings increase. The factors contributing to the overall increase in earnings were partially offset by lower interest income of $8.1 million (due to lower interest collected from the Company s Exploration and Production segment as a result of the aforementioned November 2010 debt repayment), lower margins of $6.7 million (due to a decrease in timber harvested as a result of the sale of the Company s timber harvesting and milling operations in September 2010), higher property, franchise and other taxes of $1.4 million (due to an increase in capital stock expense recorded during the year ended September 30, 2011 related to fiscal year 2010) and higher operating expenses of $0.9 million (mostly due to an increase in Midstream Corporation s operating activities). Additionally, the Company recorded a loss from unconsolidated subsidiaries of $0.5 million during the year ended September 30, 2011 compared to income of $1.6 million during the year ended September 30, 2010. The change in income (loss) from unconsolidated subsidiaries reflects the sale of Seneca Energy and Model City combined with the dormancy of ESNE.

2010 Compared with 2009

All Other and Corporate operations had a loss from continuing operations of $1.4 million in 2010 compared with earnings from continuing operations of $0.5 million in 2009. The overall decrease was due to higher interest expense of $3.8 million (primarily the result of higher borrowings at a higher interest rate due to the $250 million of 8.75% notes issued in April 2009), higher income tax expense of $3.7 million (due to a higher effective tax rate), higher depreciation and depletion expense of $2.4 million (mostly attributable to increased depletion expense due to an increase in timber harvested from Company owned lands), and higher operating expenses of $1.0 million (mostly attributable to an increase in Midstream Corporation s operating activities). In addition, the non-recurrence of a gain resulting from a death benefit on corporate-owned life insurance policies held by the Company of $2.3 million that occurred during the quarter ended December 31, 2008 further reduced earnings. The negative earnings impact associated with items mentioned above were partially offset by higher margins of $6.5 million and higher interest income of $3.1 million. The increase in margins was mostly attributable to higher margins from log and lumber sales (partially due to the increase in timber harvested from low cost basis, Company owned lands) coupled with higher revenues from Midstream Corporation s gathering operations. The increase in interest income was due to higher intercompany interest collected from the Company s other operating segments as a result of the allocation of the aforementioned April 2009 debt issuance. In addition, during the quarter ended December 31, 2008, ESNE, an unconsolidated subsidiary of Horizon Power, recorded an impairment charge of $3.6 million, which did not recur. Horizon Power s 50% share of the impairment was $1.8 million ($1.1 million on an after tax basis).

INTEREST INCOME

Interest income was $0.8 million lower in 2011 as compared to 2010. Lower cash investment balances and interest rates on these balances was the primary factor contributing to this decrease.

Interest income was $2.0 million lower in 2010 as compared to 2009. Lower interest rates on cash investment balances was the primary factor contributing to this decrease.

OTHER INCOME

Other income was $3.1 million higher in 2011 as compared to 2010. This increase is attributable to a $0.5 million gain on corporate-owned life insurance policies recognized during the second quarter of fiscal 2011 and a $0.4 million gain on the sale of Horizon Energy Development recognized during the first quarter of fiscal 2011. In addition, there was a $2.0 million increase in allowance for funds used during construction in the Pipeline and Storage segment as well as a $0.3 million gain resulting from the auction of some remaining timber mill equipment during 2011.

Other income was $4.6 million lower in 2010 as compared to 2009. This decrease is attributable to a $2.1 million decrease in the allowance for funds used during construction, which is primarily due to the completion of the Empire Connector project in December 2008. In addition, a death benefit gain on corporate-owned life insurance policies of $2.3 million recognized during the first quarter of 2009 did not recur in 2010.

INTEREST CHARGES

Although most of the variances in Interest Charges are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis:

Interest on long-term debt decreased $13.6 million in 2011 as compared to 2010. This decrease is primarily the result of a lower average amount of long-term debt outstanding and slightly lower average interest rates. The Company repaid $200 million of 7.5% notes that matured in November 2010. In addition, there was an increase in capitalized interest associated with increased capital expenditures in the Marcellus Shale area of the Appalachian region, which decreased interest expense by $0.5 million in comparison to prior year.

Interest on long-term debt increased $7.8 million in 2010 as compared to 2009. The increase in 2010 was primarily the result of a higher average amount of long-term debt outstanding combined with higher average interest rates. In April 2009, the Company issued $250 million of 8.75% senior, unsecured notes due in May 2019. This increase was partially offset by the repayment of $100 million of 6% medium-term notes that matured in March 2009. In addition, during fiscal 2009, the Exploration and Production segment significantly increased its capital expenditures related to unproved properties in the Marcellus Shale area of the Appalachian region. As a result, the Company capitalized interest costs associated with capital expenditures, which decreased interest expense by $1.1 million.

Other interest charges decreased $2.2 million in 2011 compared to 2010. The decrease is mainly attributable to a $1.6 million decrease in interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment, and a $0.5 million increase in the allowance for borrowed funds used during construction resulting from current expansion projects in the Pipeline and Storage segment.

Other interest charges decreased $0.6 million in 2010 compared to 2009. The decrease is mainly attributable to a $1.4 million decrease in interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment, which was partially offset by a $0.9 million decrease in the allowance for borrowed funds used during construction resulting from the completion of the Empire Connector in December 2008.

CAPITAL RESOURCES AND LIQUIDITY

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

Sources (Uses) of Cash

	Year Ended September 30		
	2011	2010 (Millions)	2009
Provided by Operating Activities	$ 677.3	$ 459.7	$ 611.8
Capital Expenditures	(837.6)	(455.8)	(313.6)
Investment in Subsidiary, Net of Cash Acquired			(34.9)
Net Proceeds from Sale of Timber Mill and Related Assets		15.8	
Net Proceeds from Sale of Landfill Gas Pipeline Assets		38.0	
Net Proceeds from Sale of Unconsolidated Subsidiaries	59.4		
Net Proceeds from Sale of Oil and Gas Producing Properties	63.5		3.6
Other Investing Activities	(2.9)	(0.3)	(2.8)
Reduction of Long-Term Debt	(200.0)		(100.0)
Change in Notes Payable to Banks and Commercial Paper	40.0		
Net Proceeds from Issuance of Long-Term Debt			247.8
Net Proceeds from Issuance (Repurchase) of Common Stock	(0.6)	26.0	28.2
Dividends Paid on Common Stock	(114.6)	(109.5)	(104.2)
Excess Tax (Costs) Benefits Associated with Stock- Based Compensation Awards	(1.2)	13.2	5.9
Net Increase (Decrease) in Cash and Temporary Cash Investments	$ (316.7)	$ (12.9)	$ 341.8

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, impairment of investment in partnership, deferred income taxes and income or loss from unconsolidated subsidiaries net of cash distributions. Net income available for common stock is also adjusted for the gain on sale of unconsolidated subsidiaries and the gain on sale of discontinued operations.

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

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

Net cash provided by operating activities totaled $677.3 million in 2011, an increase of $217.6 million compared with the $459.7 million provided by operating activities in 2010. The increase is primarily due to higher cash receipts from the sale of natural gas production in the Exploration and Production segment. From a consolidated perspective, the Company s cash provided by operating activities also increased during 2011 due to income tax refunds received during the year as compared to income taxes paid during 2010.

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Net cash provided by operating activities totaled $459.7 million in 2010, a decrease of $152.1 million compared with the $611.8 million provided by operating activities in 2009. The decrease is primarily due to the timing of gas cost recovery in the Utility segment. As gas prices decreased significantly during 2009, the Company s Utility segment experienced an over-recovery of gas costs that was reflected in Amounts Payable to Customers on the Company s Consolidated Balance Sheet. Since September 30, 2009, the Company has been refunding that over-recovery to its customers. From a consolidated perspective, higher interest payments on long-term debt also contributed to the decrease in cash provided by operating activities.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company s expenditures from continuing operations for long-lived assets totaled $854.2 million, $501.4 million and $341.4 million in 2011, 2010 and 2009, respectively. The table below presents these expenditures:

	Year Ended September 30		
	2011	2010 (Millions)	2009
Utility:			
Capital Expenditures	$ 58.4	$ 58.0	$ 56.2
Pipeline and Storage:			
Capital Expenditures	129.2(1)	37.9	52.5(4)
Exploration and Production:			
Capital Expenditures	648.8(1)(2)	398.2(2)(3)	188.3(3)
Investment in Subsidiary			34.9
All Other and Corporate:			
Capital Expenditures	17.8(1)	7.3(3)	9.8(3)
Eliminations			(0.3)(5)
Total Expenditures from Continuing Operations	$ 854.2	$ 501.4(6)	$ 341.4(6)

(1) Capital expenditures for the Exploration and Production segment for 2011 include $63.5 million of accrued capital expenditures, the majority of which was in the Appalachian region. Capital expenditures for the Pipeline and Storage segment for 2011 include $7.3 million of accrued capital expenditures. In addition, capital expenditures for All Other for 2011 include $1.4 million of accrued capital expenditures. These amounts have been excluded from the Consolidated Statement of Cash Flows at September 30, 2011 since they represent non-cash investing activities at that date.

(2) Capital expenditures for the Exploration and Production segment for 2011 exclude $55.5 million of accrued capital expenditures, the majority of which was in the Appalachian region. This amount was accrued at September 30, 2010 and paid during the year ended September 30, 2011. This amount was included in the 2010 capital expenditures shown in the table above, but was excluded from the Consolidated Statement of Cash Flows at September 30, 2010 since it represented a non-cash investing activity at that date. This amount has been included in the Consolidated Statement of Cash Flows at September 30, 2011.

(3) Capital expenditures for the Exploration and Production segment for 2010 exclude $9.1 million of accrued capital expenditures, the majority of which was in the Appalachian region. Capital expenditures for All Other for 2010 exclude $0.7 million of accrued capital expenditures related to the construction of the Midstream Covington Gathering System. Both of these amounts were accrued at September 30, 2009 and paid during the year ended September 30, 2010. These amounts were included in the 2009 capital expenditures shown in the table above, but were excluded from the Consolidated Statement of Cash Flows at September 30, 2009 since they represented non-cash investing activities at

that date. These amounts have been included in the Consolidated Statement of Cash Flows at September 30, 2010.

(4) Amount for 2009 excludes $16.8 million of accrued capital expenditures related to the Empire Connector project accrued at September 30, 2008 and paid during the year ended September 30, 2009. This amount was included in 2008 capital expenditures, but was excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represented a non-cash investing activity at that date. The amount was included in the Consolidated Statement of Cash Flows at September 30, 2009.

(5) Represents $0.3 million of capital expenditures in the Pipeline and Storage segment for the purchase of pipeline facilities from the Appalachian region of the Exploration and Production segment during the quarter ended December 31, 2008.

(6) Excludes expenditures for long-lived assets associated with discontinued operations as follows: $0.1 million for 2010 and $0.2 million for 2009.

Utility

The majority of the Utility capital expenditures for 2011, 2010 and 2009 were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage segment s capital expenditures for 2011 and 2010 were made for additions, improvements, and replacements to this segment s transmission and gas storage systems. In addition, the Pipeline and Storage capital expenditures for 2011 include $18.1 million spent on the Line N Expansion Project, $8.1 million spent on the Lamont Phase II Project and $31.8 million spent on the Tioga County Extension Project, as discussed below. The Pipeline and Storage capital expenditure amounts for 2010 also include $6.0 million spent on the Lamont Project. The majority of the Pipeline and Storage segment s capital expenditures for 2009 were related to the Empire Connector project, which was placed into service on December 10, 2008, as well as for additions, improvements, and replacements to this segment s transmission and gas storage systems. The Empire Connector project was completed for a cost of approximately $192 million. The Company capitalized Empire Connector project costs of $27.3 million for the year ended September 30, 2009.

Exploration and Production

In 2011, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $595.8 million for the Appalachian region (including $585.1 million in the Marcellus Shale area), $47.4 million for the West Coast region and $5.6 million for the Gulf Coast region. These amounts included approximately $199.2 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian region include the Company s acquisition of oil and gas properties in the Covington Township area of Tioga County, Pennsylvania from EOG Resources, Inc. for approximately $24.1 million in November 2010. The Company funded this transaction with cash from operations.

As the Company has been accelerating its Marcellus Shale development, it has been decreasing its emphasis in the Gulf Coast region. In March 2011, the Company entered into a purchase and sale agreement to sell its off-shore oil and natural gas properties in the Gulf of Mexico effective as of January 1, 2011 and completed the sale in April 2011. The Company received net proceeds of $55.4 million from this sale. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

In May 2011, the Company sold the Sprayberry property in the West Coast region for $8.1 million. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

In 2010, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $355.7 million for the Appalachian region (including $332.4 million in the Marcellus Shale area), $27.6 million for the West Coast region and $14.9 million for the Gulf Coast region, the majority of which was for the off-shore program in the shallow waters of the Gulf of Mexico. These amounts included approximately $28.9 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian region included the Company s acquisition of two tracts of leasehold acreage for approximately $71.8 million. The Company acquired these tracts in order to expand its Marcellus Shale acreage holdings. These tracts, consisting of approximately 18,000 net acres in Tioga and Potter Counties in Pennsylvania, are geographically similar to the Company s existing Marcellus Shale acreage in the area. The transaction closed on March 12, 2010.

In 2009, the Exploration and Production segment s capital expenditures were primarily well drilling and completion expenditures and included approximately $138.6 million for the Appalachian region, $31.4 million for the West Coast region and $18.3 million for the Gulf Coast region, substantially all of which was for the off-shore program in the shallow waters of the Gulf of Mexico. These amounts included approximately $24.2 million spent to develop proved undeveloped reserves.

In July 2009, the Company s wholly-owned subsidiary in the Exploration and Production segment, Seneca, purchased Ivanhoe Energy s United States oil and gas operations for approximately $34.9 million (net of cash acquired). This purchase complements the segment s existing oil producing assets in the Midway Sunset Field in California.

All Other and Corporate

In 2011, the majority of the All Other category s capital expenditures for long-lived assets were primarily for the construction of Midstream Corporation s Trout Run Gathering System, as discussed below, as well as for the expansion of Midstream Corporation s Covington Gathering System in Tioga County, Pennsylvania.

In 2010 and 2009, the majority of the All Other category s capital expenditures for long-lived assets were for the construction of Midstream Corporation s Covington Gathering System, which was placed in service during fiscal 2010.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, is developing a gathering system in Lycoming County, Pennsylvania. The project, called the Trout Run Gathering System, is anticipated to be placed in service in January 2012. The system will consist of approximately 26 miles of backbone and in-field gathering system at a cost of approximately $60 million. As of September 30, 2011, the Company has spent approximately $15.5 million in costs related to this project.

On September 17, 2010, the Company completed the sale of its sawmill in Marienville, Pennsylvania, including approximately 23 million board feet of logs and timber consisting of yard inventory along with unexpired timber cutting contracts and certain land and timber holdings designed to provide the purchaser with a supply of logs for the mill. Despite this sale, the Company has retained substantially all of its land and timber holdings, along with mineral rights on land to be sold. The Company will maintain a forestry operation; however, as part of this change in focus, the Company will no longer be processing lumber products. The Company received proceeds of approximately $15.8 million from the sale. In addition, the purchaser assumed approximately $7.4 million in payment obligations under the Company s timber cutting contracts with various timber suppliers. There was not a material impact to earnings from this sale.

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Estimated Capital Expenditures

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

	Year Ended September 30 2012	2013 (Millions)	2014
Utility	$ 58.0	$ 58.0	$ 58.0
Pipeline and Storage	161.5	122.5	312.1
Exploration and Production(1)	858.5	925.3	1,014.7
All Other	84.8	10.5	10.4
	$ 1,162.8	$ 1,116.3	$ 1,395.2

(1) Includes estimated expenditures for the years ended September 30, 2012, 2013 and 2014 of approximately $264 million, $166 million and $20 million, respectively, to develop proved undeveloped reserves. The Company is committed to developing its proved undeveloped reserves within five years as required by the SEC s final rule on Modernization of Oil and Gas Reporting.

Utility

Estimated capital expenditures for the Utility segment in 2012 will be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment.

Pipeline and Storage

Estimated capital expenditures for the Pipeline and Storage segment in 2012 will be concentrated on the construction of new pipeline and compressor stations to support expansion projects, the replacement of transmission and storage lines, the reconditioning of storage wells and improvements of compressor stations.

In light of the growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia specifically in the Marcellus Shale producing area Supply Corporation and Empire are actively pursuing several expansion projects and paying for preliminary survey and investigation costs, which are initially recorded as Deferred Charges on the Consolidated Balance Sheet. An offsetting reserve is established as those preliminary survey and investigation costs are incurred, which reduces the Deferred Charges balance and increases Operation and Maintenance Expense on the Consolidated Statement of Income. The Company reviews all projects on a quarterly basis, and if it is determined that it is highly probable that the project will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. After the reversal of the reserve, the amounts remain in Deferred Charges until such time as capital expenditures for the project have been incurred and activities that are necessary to get the construction project ready for its intended use are in progress. At that point, the balance is transferred from Deferred Charges to Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet. As of September 30, 2011, the total amount reserved for the Pipeline and Storage segment s preliminary survey and investigation costs was $7.0 million.

Supply Corporation and Empire are moving forward with several projects designed to move anticipated Marcellus production gas to other interstate pipelines and to markets beyond the Supply Corporation and Empire pipeline systems.

Supply Corporation has signed a precedent agreement to provide 320,000 Dth/day of firm transportation capacity in conjunction with its Northern Access expansion project. Upon satisfaction of the conditions in the precedent agreement, Statoil Natural Gas LLC (Statoil) will enter into a 20-year firm transportation agreement for 320,000 Dth/day. This capacity will provide Statoil with a firm transportation path from the Tennessee Gas Pipeline (TGP) 300 Line at Ellisburg to the TransCanada Pipeline at Niagara. This path is attractive because it provides a route for Marcellus shale gas, principally along the TGP 300 Line in northern

Pennsylvania, to be transported from the Marcellus supply basin to northern markets. Supply Corporation filed an application for FERC authorization of the project on March 7, 2011, and received its Certificate on October 20, 2011. The project facilities involve approximately 9,500 horsepower of additional compression at Supply Corporation s existing Ellisburg Station and a new approximately 5,000 horsepower compressor station in East Aurora, New York, along with other system enhancements including enhancements to the jointly owned Niagara Spur Loop Line. Service is expected to begin in November 2012. The cost estimate for the Northern Access expansion is $62 million, all of which is expected to be spent in fiscal 2012 and 2013, except for approximately $2.4 million already spent through September 30, 2011. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. The $2.4 million spent has been capitalized as Construction Work in Progress.

Another expansion project involves new compression along Supply Corporation s Line N (Line N Expansion Project), increasing that line s capacity by 160,000 Dth/day into Texas Eastern s Holbrook Station (TETCO Holbrook) in southwestern Pennsylvania. The project will allow Marcellus production located in the vicinity of Line N to flow south and access markets off Texas Eastern s system. Two service agreements totaling 160,000 Dth/day of firm transportation have been executed. The FERC issued the NGA Section 7(c) certificate on December 16, 2010, and the project was placed into service on October 19, 2011. The cost estimate for the Line N Expansion Project is $20 million. As of September 30, 2011, approximately $18.1 million has been spent on the Line N Expansion Project, all of which has been capitalized as Construction Work in Progress.

Supply Corporation has also executed a precedent agreement for 150,000 Dth/day of additional capacity on Line N to TETCO Holbrook and has designed a project for this shipper to be ready for service beginning November 2012 (Line N 2012 Expansion Project). On July 8, 2011, Supply Corporation filed for FERC authorization to construct the Line N 2012 Expansion Project which consists of an additional 20,620 horsepower of compression at its Buffalo Compressor Station, and the replacement of 4.85 miles of 20 pipe with 24 pipe, to enhance the integrity and reliability of its system and to create the additional capacity. The preliminary cost estimate for the Line N 2012 Expansion Project is approximately $30.0 million for the incremental capacity plus approximately $5.8 million allocated to system replacement. These amounts are expected to be spent in fiscal 2012, except for approximately $2.4 million already spent through September 30, 2011. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. The Company has determined that it is highly probable that this project will be built. Accordingly, previous reserves have been reversed and the project costs have been capitalized as Construction Work in Progress.

Following up on Supply Corporation s Lamont Project which went into service on June 15, 2010, a second Lamont expansion (Lamont Phase II Project) has been fully subscribed and is now in service. Supply Corporation has two executed service agreements for the full capacity of this project. With the addition of 3,400 horsepower of compression at Lamont, 10,000 Dth/day of incremental firm capacity was placed in service on July 1, 2011, and an additional 40,000 Dth/day commenced on October 1, 2011. As of September 30, 2011, approximately $8.1 million has been spent on the Lamont Phase II project, all of which has been capitalized.

In addition, Supply Corporation continues to actively pursue its largest planned expansion, the West-to-East (W2E) pipeline project, which is designed to transport locally produced Marcellus natural gas supplies to the Ellisburg/Leidy/Corning area. Supply Corporation anticipates that the development of the W2E project will occur in phases. As currently envisioned, the initial phases of W2E, referred to as the W2E Overbeck to Leidy project, are designed to transport at least 425,000 Dth/day, and involves construction of a new 82-mile pipeline through Elk, Cameron, Clinton, Clearfield and Jefferson Counties to the Leidy Hub, from Marcellus and other producing areas along over 300 miles of Supply Corporation s existing pipeline system. The W2E Overbeck to Leidy project also includes a total of approximately 25,000 horsepower of compression at two separate stations. The project may be built in phases depending on the development of Marcellus production along the corridor, with the first facilities expected to go in service in late 2013 or late 2014.

Following an Open Season that concluded on October 8, 2009, Supply Corporation executed precedent agreements to provide 125,000 Dth/day of firm transportation on the W2E Overbeck to Leidy project. Supply Corporation is pursuing post-Open Season capacity requests for the remaining capacity. On March 31, 2010, the FERC granted Supply Corporation s request for a pre-filing environmental review of the W2E Overbeck to Leidy project, and Supply Corporation is in the process of preparing an NGA Section 7(c) application. The capital cost of the W2E Overbeck to Leidy project is estimated to be $290 million, approximately $264.0 million of which is expected to be spent during the period of fiscal 2012 through 2014. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2011, approximately $5.5 million has been spent to study the W2E Overbeck to Leidy project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2011.

Empire has executed service agreements for all 350,000 Dth/day of incremental firm transportation capacity in its Tioga County Extension Project. This project will transport Marcellus production from new interconnections at the southern terminus of a 15-mile extension of its Empire Connector line, in Tioga County, Pennsylvania. Empire s cost estimate for the Tioga County Extension Project is approximately $49 million, of which approximately $31.8 million has been spent through September 30, 2011 and has been capitalized as Construction Work in Progress. The remainder is expected to be spent in fiscal 2012 and is included as Pipeline and Storage segment estimated capital expenditures in the table above. This project will enable shippers to deliver their natural gas at existing Empire interconnections with Millennium Pipeline at Corning, New York, with the TransCanada Pipeline at the Niagara River at Chippawa, and with utility and power generation markets along its path, as well as to a planned new interconnection with TGP s 200 Line (Zone 5) in Ontario County, New York. On August 26, 2010, Empire filed an NGA Section 7(c) application to the FERC for approval of the project and the FERC issued the certificate on May 19, 2011. Empire has accepted the certificate, received a FERC Notice to Proceed and on July 7, 2011 commenced construction. These facilities were placed fully in service on November 22, 2011.

On December 17, 2010, Empire concluded an Open Season for up to 260,000 Dth/day of additional capacity from Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line, as well as additional short-haul capacity to Millennium Pipeline at Corning (Central Tioga County Extension). Empire is evaluating the substantial market interest resulting from this Open Season, which was for more than 260,000 Dth/day of capacity, and is studying the facility design that would be necessary to provide the requested service. The Central Tioga County Extension project may involve up to 25,000 horsepower of compression at up to three new stations and a 25 mile 24 pipeline extension, at a preliminary cost estimate of $135 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2011, approximately $0.2 million has been spent to study the Central Tioga County Extension project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2011.

The Company has largely been financing the Line N Expansion Projects, the Lamont Phase II Project, the Northern Access expansion project, the W2E Overbeck to Leidy project, and the Tioga County Extension Projects, all of which are discussed above, with cash from operations. Going forward, while the Company expects to use cash from operations as the first means of financing these projects, it is expected that the Company will increase its use of short-term borrowings in fiscal 2012. The Company also plans to issue additional long-term debt in fiscal 2012.

Exploration and Production

Estimated capital expenditures in 2012 for the Exploration and Production segment include approximately $808.5 million for the Appalachian region and $50.0 million for the West Coast region. The Company anticipates drilling 100 to 125 net horizontal wells in the Marcellus Shale during 2012.

Estimated capital expenditures in 2013 for the Exploration and Production segment include approximately $882.0 million for the Appalachian region and $43.3 million for the West Coast region. The Company anticipates drilling 110 to 140 net horizontal wells in the Marcellus Shale during 2013.

Estimated capital expenditures in 2014 for the Exploration and Production segment include approximately $974.2 million for the Appalachian region and $40.5 million for the West Coast region. The Company anticipates drilling 140 to 170 net horizontal wells in the Marcellus Shale during 2014.

It is anticipated that these future capital expenditures will be funded with a combination of cash from operations, short-term borrowings, and long-term debt. Natural gas and crude oil prices combined with production from existing wells will be a significant factor in determining how much of the capital expenditures are funded from cash from operations. While the Company expects to use cash from operations as the first means of financing these expenditures, it is expected that the Company will increase its use of short-term borrowings in fiscal 2012. The Company also plans to issue additional long-term debt in fiscal 2012.

All Other and Corporate

Estimated capital expenditures in 2012 for the All Other and Corporate category will primarily be for the construction of anticipated gathering systems, including completing the construction of Midstream Corporation s Trout Run Gathering System, as discussed above, and construction of Midstream Corporation s Mt. Jewett and Owls Nest Gathering Systems, discussed below.

Midstream Corporation is planning to construct a gathering system in McKean County, Pennsylvania. The project, called the Mt. Jewett Gathering System, is anticipated to be placed in service in June 2012. The gathering system will cost approximately $22 million. These expenditures are included as All Other category estimated capital expenditures in the table above. As of September 30, 2011, the Company has not incurred any costs related to this project.

Midstream Corporation is also planning to construct a gathering system in Elk County, Pennsylvania. The project, called the Owls Nest Gathering System, is anticipated to be placed in service in April 2012. The gathering system will cost approximately $17 million. These expenditures are included as All Other category estimated capital expenditures in the table above. As of September 30, 2011, the Company has not incurred any costs related to this project.

The Company anticipates funding the Midstream Corporation projects with cash from operations, short-term borrowings, and long-term debt. While the Company expects to use cash from operations as the first means of financing these projects, it is expected that the Company will increase its use of short-term borrowings in fiscal 2012. The Company also plans to issue additional long-term debt in fiscal 2012.

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

FINANCING CASH FLOW

Consolidated short-term debt increased $40.0 million during the year ended September 30, 2011 and did not exceed $40.0 million outstanding during the year. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At September 30, 2011, the Company had outstanding commercial paper of $40.0 million and no outstanding short-term notes payable to banks.

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As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $385.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or substantially replaced by similar lines.

The total amount available to be issued under the Company s commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million, which commitment extends through September 30, 2013. Under the Company s committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2013. At September 30, 2011, the Company s debt to capitalization ratio (as calculated under the facility) was .37. The constraints specified in the committed credit facility would permit an additional $2.42 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company s debt to capitalization ratio would exceed .65. If a downgrade in any of the Company s credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company s existing indenture covenants, at September 30, 2011, the Company would have been permitted to issue up to a maximum of $1.77 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company s present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company s ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt.

The Company s 1974 indenture pursuant to which $99.0 million (or 9.4%) of the Company s long-term debt (as of September 30, 2011) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company s $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2011, the Company did not have any debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 6.85% at September 30, 2011 and 6.95% at September 30, 2010. If the Company were to issue 10-year long-term debt today, its borrowing costs might be expected to be in the range of 4.375% to 5.375%. Refer to Interest Rate Risk in this Item for a more detailed breakdown of the Company s embedded cost of long-term debt.

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Current Portion of Long-Term Debt at September 30, 2011 consists of $150 million of 6.70% medium-term notes that matured in November 2011. Currently, the Company expects to refund these medium-term notes in November 2011 with cash on hand, short-term borrowings and/or long-term debt. In November 2010, the Company repaid $200 million of 7.50% notes that matured on November 22, 2010 that were classified as Current Portion of Long-Term Debt at September 30, 2010.

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

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company s consolidated subsidiaries have operating leases, the majority of which are with the Utility and the Pipeline and Storage segments, having a remaining lease commitment of approximately $35.0 million. These leases have been entered into for the use of buildings, vehicles, construction tools, meters and other items and are accounted for as operating leases.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company s expected future contractual cash obligations as of September 30, 2011, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2012	2013	2014	2015 (Millions)	2016	Thereafter	Total
Long-Term Debt, including interest expense(1)	$ 213.2	$ 304.2	$ 48.7	$ 48.7	$ 48.7	$ 791.1	$ 1,454.6
Operating Lease Obligations	$ 5.7	$ 5.0	$ 4.5	$ 4.3	$ 4.2	$ 11.3	$ 35.0
Purchase Obligations:							
Gas Purchase Contracts(2)	$ 264.4	$ 39.1	$ 6.8	$ 0.9	$ 0.5	$ 0.1	$ 311.8
Transportation and Storage Contracts	$ 53.2	$ 50.5	$ 50.2	$ 50.0	$ 26.0	$ 11.3	$ 241.2
Well Drilling, Hydraulic Fracturing and Compression Obligations	$ 93.9	$ 73.5	$ 12.9	$	$	$	$ 180.3
Pipeline and Gathering System Expansion Projects	$ 83.1	$	$	$	$	$	$ 83.1
Other	$ 25.2	$ 5.2	$ 4.8	$ 4.3	$ 4.2	$ 11.2	$ 54.9

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

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

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

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the Consolidated Balance Sheets in accordance with the authoritative guidance (see Item 7, MD&A under the heading Critical Accounting Estimates Accounting for Derivative Financial Instruments); (ii) NFR obligations to purchase gas or to purchase gas transportation/storage services where the amounts due on those obligations each month are included on the Consolidated Balance Sheets as a current liability; and (iii) other obligations

which are reflected on the Consolidated Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note I Commitments and Contingencies, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company s present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) that covers a majority of the Company s employees. The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it will continue making contributions to the Retirement Plan. During 2011, the Company contributed $53.6 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2012 will be in the range of $40.0 million to $50.0 million. Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in 2012 in order to be in compliance with the Pension Protection Act of 2006. The Company expects that all subsidiaries having employees covered by the Retirement Plan will make contributions to the Retirement Plan. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments or through short-term borrowings or through cash from operations.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The Company has established VEBA trusts and 401(h) accounts for its other post-retirement benefits. The Company has been making contributions to its VEBA trusts and 401(h) accounts over the last several years and anticipates that it will continue making contributions to the VEBA trusts and 401(h) accounts. During 2011, the Company contributed $25.2 million to its VEBA trusts and 401(h) accounts. The Company anticipates that the annual contribution to its VEBA trusts and 401(h) accounts in 2012 will be in the range of $15.0 million to $25.0 million. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.

As of September 30, 2011, the Company has a federal net operating loss (NOL) carryover of $221 million, which expires in varying amounts between 2023 and 2031. Approximately $23 million of this NOL is subject to certain annual limitations, and $48 million is attributable to excess tax deductions related to stock based compensation. In addition, the Company has state NOL carryovers in Pennsylvania, California and New York of $129 million, $62 million and $38 million, respectively, which begin to expire in varying amounts between 2029 and 2031. No valuation allowance was recorded on the federal or state NOL carryovers because of management s determination that the amounts will be fully utilized during the carryforward period.

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company, in its Exploration and Production segment, Energy Marketing segment and Pipeline and Storage segment, uses various derivative financial instruments (derivatives), including price swap agreements and futures contracts, as part of the Company s overall energy commodity price risk management strategy. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company s risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from, or pay to, the respective counterparties at September 30, 2011 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial instruments.

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives 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. The Company continues to monitor these developments but cannot predict the impact the Dodd-Frank Act may ultimately have on its operations.

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

The Level 3 net liabilities amount to $5.4 million at September 30, 2011 and represent 3.8% of the Total Net Assets shown in Item 8 at Note F Fair Value Measurements at September 30, 2011.

The Company uses the crude oil swaps classified as Level 3 to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative net liabilities (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities.

The increase in the net fair value of the Level 3 positions from October 1, 2010 to September 30, 2011, as shown in Item 8 at Note F, was attributable to a decrease in the commodity price of crude oil relative to the swap price during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at September 30, 2011.

The fair value of all of the Company s Net Derivative Assets was reduced by $2.0 million based upon the Company s assessment of counterparty credit risk (for the Company s derivative assets) and the Company s credit risk (for the Company s derivative liabilities). The Company applied default probabilities to the anticipated cash flows that it was expecting to receive and pay to its counterparties to calculate the credit reserve.

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The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2011. At September 30, 2011, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2016.

Natural Gas Price Swap Agreements

	Expected Maturity Dates					
	2012	2013	2014	2015	2016	Total
Notional Quantities (Equivalent Bcf)	37.4	24.2	4.7	0.1	0.1	66.5
Weighted Average Fixed Rate (per Mcf)	$ 5.83	$ 5.67	$ 5.90	$ 5.77	$ 5.77	$ 5.78
Weighted Average Variable Rate (per Mcf)	$ 4.32	$ 4.92	$ 5.23	$ 5.58	$ 5.94	$ 4.61

Of the total Bcf above, 2.1 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $5.41 per Mcf. The remaining 64.4 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $5.79 per Mcf.

Crude Oil Price Swap Agreements

	Expected Maturity Dates			
	2012	2013	2014	Total
Notional Quantities (Equivalent bbls)	1,620,000	924,000	192,000	2,736,000
Weighted Average Fixed Rate (per bbl)	$ 77.03	$ 86.21	$ 94.90	$ 81.38
Weighted Average Variable Rate (per bbl)	$ 82.13	$ 84.86	$ 86.49	$ 83.36

At September 30, 2011, the Company would have received from its respective counterparties an aggregate of approximately $75.1 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have to pay its respective counterparties an aggregate of approximately $5.4 million to terminate the crude oil price swap agreements outstanding at September 30, 2011.

At September 30, 2010, the Company had natural gas price swap agreements covering 38.3 Bcf at a weighted average fixed rate of $6.88 per Mcf. The Company also had crude oil price swap agreements covering 2,688,000 bbls at a weighted average fixed rate of $69.89 per bbl.

The following table discloses the net contract volume purchased (sold), weighted average contract prices and weighted average settlement prices by expected maturity date for futures contracts used to manage natural gas price risk. At September 30, 2011, the Company held no futures contracts with maturity dates extending beyond 2014.

Futures Contracts

	Expected Maturity Dates			
	2012	2013	2014	Total
Net Contract Volume Purchased (Sold) (Equivalent Bcf)	1.9	0.3	0.1(1)	2.3
Weighted Average Contract Price (per Mcf)	$ 5.11	$ 5.40	$ 6.03	$ 5.14
Weighted Average Settlement Price (per Mcf)	$ 5.32	$ 5.74	$ 6.62	$ 5.36

(1) The Energy Marketing segment has purchased 4 futures contracts (1 contract = 10,000 Dth) for 2014.

At September 30, 2011, the Company had long (purchased) futures contracts covering 8.6 Bcf of gas extending through 2014 at a weighted average contract price of $5.21 per Mcf and a weighted average settlement price of $4.30 per Mcf. Of this amount, 8.0 Bcf is accounted for as fair value hedges and are used

by the Company s Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed to due to the fixed price gas sales commitments that it enters into with certain residential, commercial, industrial, public authority and wholesale customers. The remaining 0.6 Bcf is accounted for as cash flow hedges used to hedge against rising prices related to anticipated gas purchases for potential injections into storage. The Company would have had to pay $7.8 million to terminate these futures contracts at September 30, 2011.

At September 30, 2011, the Company had short (sold) futures contracts covering 6.3 Bcf of gas extending through 2013 at a weighted average contract price of $5.04 per Mcf and a weighted average settlement price of $4.32 per Mcf. Of this amount, 5.5 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Energy Marketing segment. The remaining 0.8 Bcf is accounted for as fair value hedges used to hedge against falling prices, a risk to which the Energy Marketing segment is exposed to due to the fixed price gas purchase commitments that it enters into with its natural gas suppliers. The Company would have received $4.5 million to terminate these futures contracts at September 30, 2011.

At September 30, 2010, the Company had long (purchased) futures contracts covering 14.2 Bcf of gas extending through 2013 at a weighted average contract price of $5.47 per Mcf and a weighted average settlement price of $4.54 per Mcf.

At September 30, 2010, the Company had short (sold) futures contracts covering 6.5 Bcf of gas extending through 2011 at a weighted average contract price of $5.52 per Mcf and a weighted average settlement price of $4.38 per Mcf.

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company s counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with eleven counterparties of which ten are in a net gain position. On average, the Company had $7.6 million of credit exposure per counterparty in a gain position at September 30, 2011. The maximum credit exposure per counterparty in a gain position at September 30, 2011 was $12.2 million. The Company had not received any collateral from these counterparties at September 30, 2011 since the Company s gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties credit ratings declined to levels at which the counterparties were required to post collateral.

As of September 30, 2011, eight of the eleven counterparties to the Company s outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company s credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company s credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company s outstanding derivative instrument contracts were in a liability position (or if the current liability were larger) and/or the Company s credit rating declined, then additional hedging collateral deposits would be required. At September 30, 2011, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $51.1 million according to the Company s internal model (discussed in Item 8 at Note F Fair Value Measurements). At September 30, 2011, the fair market value of the derivative financial instrument liability with a credit-risk related contingency feature was $6.4 million according to the Company s internal model (discussed in Item 8 at Note F Fair Value Measurements). For its over-the-counter crude oil swap agreements, which are in a liability position, the Company was required to post $14.2 million in hedging collateral deposits at September 30, 2011. This is discussed in Item 8 at Note A under Hedging Collateral Deposits.

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For its exchange traded futures contracts which are in a liability position, the Company had posted $5.5 million in hedging collateral as of September 30, 2011. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company s requirement to post hedging collateral deposits is based on the fair value determined by the Company s counterparties, which may differ from the Company s assessment of fair value. Hedging collateral deposits may also include closed derivative positions in which the broker has not cleared the cash from the account to offset the derivative liability. The Company records liabilities related to closed derivative positions in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. These liabilities are relieved when the broker clears the cash from the hedging collateral deposit account. This is discussed in Item 8 at Note A under Hedging Collateral Deposits.

Interest Rate Risk

The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company s long-term fixed rate debt as well as the other long-term debt of certain of the Company s subsidiaries:

	Principal Amounts by Expected Maturity Dates (Dollars in millions)						
	2012	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**
Long-Term Fixed Rate Debt	$ 150.0	$ 250.0	$	$	$	$ 649.0	$ 1,049.0
Weighted Average Interest Rate Paid	6.7%	5.3%				7.5%	6.9%
Fair Value of Long-Term Fixed Rate Debt = $1,198.6							

RATE AND REGULATORY MATTERS

Utility Operation

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

New York Jurisdiction

Customer delivery rates charged by Distribution Corporation s New York division were established in a rate order issued on December 21, 2007 by the NYPSC. The rate order approved a revenue increase of $1.8 million annually, together with a surcharge that would collect up to $10.8 million to cover expenses for implementation of an efficiency and conservation incentive program. The rate order further provided for a return on equity of 9.1%. In connection with the efficiency and conservation program, the rate order approved a revenue decoupling mechanism. The revenue decoupling mechanism decouples revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized usage per customer. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. The Company surcharges or credits any difference from the average weather normalized usage per customer account. The surcharge or credit is calculated to recover total margin for the most recent twelve-month period ending December 31, and is applied to customer bills annually, beginning March 1st.

On April 18, 2008, Distribution Corporation filed an appeal with Supreme Court, Albany County, seeking review of the rate order. The appeal contended, among other things, that the NYPSC improperly disallowed recovery of certain environmental clean-up costs. Following further appeals, on March 29, 2011,

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the Court of Appeals, the state s highest court, issued a judgment and opinion in favor of Distribution Corporation. The matter was remanded to the NYPSC to be implemented consistent with the decision of the court.

Pennsylvania Jurisdiction

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

Pipeline and Storage

Supply Corporation filed a general rate case with the FERC on October 31, 2011, proposing rate increases to be effective December 1, 2011. The proposed rates reflect a cost of service of $199.3 million, a rate base of $441.7 million, and a proposed cost of equity of 13.5% per year. If the FERC accepts the filed rates, it would typically suspend the effective date of the proposed rate increases for five months, or until May 1, 2012, when the increased rates will be made effective, subject to refund. If the rates finally approved at the end of the proceeding exceed the rates that were in effect at October 31, 2011 but are less than the rates put into effect subject to refund on May 1, 2012, Supply Corporation will be required to refund the difference between the rates collected subject to refund and the final approved rates, with interest at the FERC-approved rate. If the rates approved at the end of the proceeding are lower than the rates in effect at October 31, 2011, the refund obligation will be limited to the difference between the rates in effect at October 31, 2011 and the rates put into effect subject to refund on May 1, 2012, with interest at the FERC-approved rate. To the extent the final FERC-approved rates are below those in effect at October 31, 2011, there is no refund for that rate differential. The final FERC-approved rates would be charged to customers only prospectively, from the date they go into effect.

Empire s new facilities (the Empire Connector project) were placed into service on December 10, 2008. As of that date, Empire became an interstate pipeline subject to FERC regulation, performing services under a FERC-approved tariff and at FERC-approved rates. The December 21, 2006 FERC order issuing Empire its Certificate of Public Convenience and Necessity requires Empire to file a cost and revenue study at the FERC following three years of actual operation as an interstate pipeline, in conjunction with which Empire will either justify Empire s existing recourse rates or propose alternative rates.

ENVIRONMENTAL MATTERS

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory policies and procedures. It is the Company s policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2011, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $17.2 million to $21.4 million. The minimum estimated liability of $17.2 million has been recorded on the Consolidated Balance Sheet at September 30, 2011. The Company expects to recover its environmental clean-up costs through rate recovery. Other than as discussed in Note I (referred to below), the Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

For further discussion refer to Item 8 at Note I Commitments and Contingencies under the heading Environmental Matters.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. 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 gas emissions from the energy industry. In April 2011, the U.S. Senate rejected bills aimed at curbing the authority of the EPA to regulate greenhouse gas emissions. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts carbon emissions could increase the Company s cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

NEW AUTHORITATIVE ACCOUNTING AND FINANCIAL REPORTING GUIDANCE

In May 2011, the FASB issued authoritative guidance regarding fair value measurement as a joint project with the IASB. The objective of the guidance was to bring together as closely as possible the fair value measurement and disclosure guidance issued by the two boards. The guidance includes a few updates to measurement guidance and some enhanced disclosure requirements. For all Level 3 fair value measurements, the guidance requires quantitative information about significant unobservable inputs used and a description of the valuation processes in place. The guidance also requires a qualitative discussion about the sensitivity of recurring Level 3 fair value measurements and information about any transfers between Level 1 and Level 2 of the fair value hierarchy. The new guidance also contains a requirement that all fair value measurements, whether they are recorded on the balance sheet or disclosed in the footnotes, be classified as Level 1, Level 2 or Level 3 within the fair value hierarchy. This authoritative guidance will be effective as of the Company s second quarter of fiscal 2012. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statement disclosures.

In June 2011, the FASB issued authoritative guidance regarding the presentation of comprehensive income. The new guidance allows companies only two choices for presenting net income and other comprehensive income: in a single continuous statement, or in two separate, but consecutive, statements. The guidance eliminates the current option to report other comprehensive income and its components in the statement of changes in equity. This authoritative guidance will be effective as of the Company s first quarter of fiscal 2013 and is not expected to have a significant impact on the Company s financial statements.

In September 2011, the FASB issued revised authoritative guidance that simplifies the testing of goodwill for impairment. The revised guidance allows companies the option to perform a qualitative assessment to determine whether further impairment testing is necessary. The revised authoritative guidance is required to be effective for the Company s annual impairment test performed in fiscal 2013. However, early adoption is permitted. The Company did not use the revised authoritative guidance in performing its annual impairment test for fiscal 2011.

EFFECTS OF INFLATION

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

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include

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

1. Factors affecting the Company s ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;

2. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;

3. Uncertainty of oil and gas reserve estimates;

4. Significant differences between the Company s projected and actual production levels for natural gas or oil;

5. Changes in the price of natural gas or oil;

6. Changes in the availability, price or accounting treatment of derivative financial instruments;

7. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, allowed rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;

8. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;

9. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company s credit ratings and changes in interest rates and other capital market conditions;

10. Changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers ability to pay for, the Company s products and services;

11. The creditworthiness or performance of the Company s key suppliers, customers and counterparties;

12. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;

13. Changes in price differential between similar quantities of natural gas at different geographic locations, and the effect of such changes on the demand for pipeline transportation capacity to or from such locations;

14. Other changes in price differentials between similar quantities of oil or natural gas having different quality, heating value, geographic location or delivery date;

15. Impairments under the SEC s full cost ceiling test for natural gas and oil reserves;

16. Significant differences between the Company s projected and actual capital expenditures and operating expenses;

17. Changes in actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company s pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;

18. Changes in demographic patterns and weather conditions;

19. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;

20. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or

21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

Industry and Market Information

The industry and market data used or referenced in this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources. Some industry and market data may also be based on good faith estimates, which are derived from the Company s review of internal information, as well as the independent sources listed above. Independent industry publications and surveys generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy and completeness of such information. While the Company believes that each of these studies and publications is reliable, the Company has not independently verified such data and makes no representation as to the accuracy of such information. Forecasts in particular may prove to be inaccurate, especially over long periods of time. Similarly, while the Company believes its internal information is reliable, such information has not been verified by any independent sources, and the Company makes no assurances that any predictions contained herein will prove to be accurate.

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

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

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Item 8 ***Financial Statements and Supplementary Data***
Index to Financial Statements

Financial Statements:

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

Supplementary Data

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2011 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2011, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

Buffalo, New York

November 23, 2011

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS

REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2011	2010	2009
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$ 1,778,842	$ 1,760,503	$ 2,051,543
Operating Expenses			
Purchased Gas	628,732	658,432	997,216
Operation and Maintenance	400,519	394,569	401,200
Property, Franchise and Other Taxes	81,902	75,852	72,102
Depreciation, Depletion and Amortization	226,527	191,199	170,620
Impairment of Oil and Gas Producing Properties			182,811
	1,337,680	1,320,052	1,823,949
Operating Income	441,162	440,451	227,594
Other Income (Expense):			
Income (Loss) from Unconsolidated Subsidiaries	(759)	2,488	3,366
Gain on Sale of Unconsolidated Subsidiaries	50,879		
Impairment of Investment in Partnership			(1,804)
Other Income	6,706	3,638	8,200
Interest Income	2,916	3,729	5,776
Interest Expense on Long-Term Debt	(73,567)	(87,190)	(79,419)
Other Interest Expense	(4,554)	(6,756)	(7,370)
Income from Continuing Operations Before Income Taxes	422,783	356,360	156,343
Income Tax Expense	164,381	137,227	52,859
Income from Continuing Operations	258,402	219,133	103,484
Discontinued Operations:			
Income (Loss) from Operations, Net of Tax		470	(2,776)
Gain on Disposal, Net of Tax		6,310	
Income (Loss) from Discontinued Operations, Net of Tax		6,780	(2,776)
Net Income Available for Common Stock	258,402	225,913	100,708
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	1,063,262	948,293	953,799
	1,321,664	1,174,206	1,054,507
Adoption of Authoritative Guidance for Defined Benefit Pension and Other Post-Retirement Plans			(804)
Dividends on Common Stock	(115,642)	(110,944)	(105,410)
Balance at End of Year	$ 1,206,022	$ 1,063,262	$ 948,293

Earnings Per Common Share:			
Basic:			
Income from Continuing Operations	$ 3.13	$ 2.70	$ 1.29
Income (Loss) from Discontinued Operations		0.08	(0.03)
Net Income Available for Common Stock	$ 3.13	$ 2.78	$ 1.26
Diluted:			
Income from Continuing Operations	$ 3.09	$ 2.65	$ 1.28
Income (Loss) from Discontinued Operations		0.08	(0.03)
Net Income Available for Common Stock	$ 3.09	$ 2.73	$ 1.25
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	82,514,015	81,380,434	79,649,965
Used in Diluted Calculation	83,670,802	82,660,598	80,628,685

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2011	2010
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$ 5,646,918	$ 5,637,498
Less Accumulated Depreciation, Depletion and Amortization	1,646,394	2,187,269
	4,000,524	3,450,229
Current Assets		
Cash and Temporary Cash Investments	80,428	397,171
Hedging Collateral Deposits	19,701	11,134
Receivables Net of Allowance for Uncollectible Accounts of $31,039 and $30,961, Respectively	131,885	132,136
Unbilled Utility Revenue	17,284	20,920
Gas Stored Underground	54,325	48,584
Materials and Supplies at average cost	27,932	24,987
Other Current Assets	38,334	115,969
Deferred Income Taxes	15,423	24,476
	385,312	775,377
Other Assets		
Recoverable Future Taxes	144,377	149,712
Unamortized Debt Expense	10,571	12,550
Other Regulatory Assets	574,644	542,801
Deferred Charges	5,552	9,646
Other Investments	79,365	77,839
Investments in Unconsolidated Subsidiaries	1,306	14,828
Goodwill	5,476	5,476
Fair Value of Derivative Financial Instruments	76,085	65,184
Other	1,530	1,983
	898,906	880,019
Total Assets	$ 5,284,742	$ 5,105,625
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value		
Authorized 200,000,000 Shares; Issued and Outstanding 82,812,677 Shares and 82,075,470 Shares, Respectively	$ 82,813	$ 82,075
Paid In Capital	650,749	645,619
Earnings Reinvested in the Business	1,206,022	1,063,262
Total Common Shareholders Equity Before Items of Other Comprehensive Loss	1,939,584	1,790,956
Accumulated Other Comprehensive Loss	(47,699)	(44,985)
Total Comprehensive Shareholders Equity	1,891,885	1,745,971
Long-Term Debt, Net of Current Portion	899,000	1,049,000
Total Capitalization	2,790,885	2,794,971
Current and Accrued Liabilities		

Notes Payable to Banks and Commercial Paper	40,000	
Current Portion of Long-Term Debt	150,000	200,000
Accounts Payable	126,709	89,677
Amounts Payable to Customers	15,519	38,109
Dividends Payable	29,399	28,316
Interest Payable on Long-Term Debt	25,512	30,512
Customer Advances	19,643	27,638
Customer Security Deposits	17,321	18,320
Other Accruals and Current Liabilities	94,787	71,592
Fair Value of Derivative Financial Instruments	9,728	20,160
	528,618	524,324
Deferred Credits		
Deferred Income Taxes	955,384	800,758
Taxes Refundable to Customers	65,543	69,585
Unamortized Investment Tax Credit	2,586	3,288
Cost of Removal Regulatory Liability	135,940	124,032
Other Regulatory Liabilities	94,684	89,334
Pension and Other Post-Retirement Liabilities	481,520	446,082
Asset Retirement Obligations	75,731	101,618
Other Deferred Credits	153,851	151,633
	1,965,239	1,786,330
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 5,284,742	$ 5,105,625

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30 2011	2010	2009
	(Thousands of dollars)		
Operating Activities			
Net Income Available for Common Stock	$ 258,402	$ 225,913	$ 100,708
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Gain on Sale of Unconsolidated Subsidiaries	(50,879)		
Gain on Sale of Discontinued Operations		(10,334)	
Impairment of Oil and Gas Producing Properties			182,811
Depreciation, Depletion and Amortization	226,527	191,809	173,410
Deferred Income Taxes	164,251	134,679	(2,521)
(Income) Loss from Unconsolidated Subsidiaries, Net of Cash Distributions	5,037	112	(466)
Impairment of Investment in Partnership			1,804
Excess Tax Costs (Benefits) Associated with Stock-Based Compensation Awards	1,224	(13,207)	(5,927)
Other	10,614	9,108	19,829
Change in:			
Hedging Collateral Deposits	(8,567)	(10,286)	(847)
Receivables and Unbilled Utility Revenue	3,887	10,262	47,658
Gas Stored Underground and Materials and Supplies	(9,934)	6,546	43,598
Unrecovered Purchased Gas Costs			37,708
Prepayments and Other Current Assets	76,411	(34,288)	2,921
Accounts Payable	37,032	8,047	(61,149)
Amounts Payable to Customers	(22,590)	(67,669)	103,025
Customer Advances	(7,995)	3,083	(8,462)
Customer Security Deposits	(999)	890	3,383
Other Accruals and Current Liabilities	1,658	(3,649)	13,676
Other Assets	17,006	7,237	(35,140)
Other Liabilities	(23,799)	1,442	(4,201)
Net Cash Provided by Operating Activities	677,286	459,695	611,818
Investing Activities			
Capital Expenditures	(837,612)	(455,764)	(313,633)
Investment in Subsidiary, Net of Cash Acquired			(34,933)
Net Proceeds from Sale of Unconsolidated Subsidiaries	59,365		
Net Proceeds from Sale of Timber Mill and Related Assets		15,770	
Net Proceeds from Sale of Landfill Gas Pipeline Assets		38,000	
Net Proceeds from Sale of Oil and Gas Producing Properties	63,501		3,643
Other	(2,908)	(251)	(2,806)
Net Cash Used in Investing Activities	(717,654)	(402,245)	(347,729)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	40,000		
Excess Tax (Costs) Benefits Associated with Stock-Based Compensation Awards	(1,224)	13,207	5,927
Net Proceeds from Issuance of Long-Term Debt			247,780
Reduction of Long-Term Debt	(200,000)		(100,000)
Net Proceeds from Issuance (Repurchase) of Common Stock	(592)	26,057	28,176
Dividends Paid on Common Stock	(114,559)	(109,596)	(104,158)
Net Cash Provided By (Used in) Financing Activities	(276,375)	(70,332)	77,725

Net Increase (Decrease) in Cash and Temporary Cash Investments	(316,743)	(12,882)	341,814
Cash and Temporary Cash Investments At Beginning of Year	397,171	410,053	68,239
Cash and Temporary Cash Investments At End of Year	$ 80,428	$ 397,171	$ 410,053
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 81,966	$ 93,333	$ 75,640
Income Taxes (Refunded)	$ (63,105)	$ 30,975	$ 40,638

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2011	**2010**	**2009**
		(Thousands of dollars)	
Net Income Available for Common Stock	$ 258,402	$ 225,913	$ 100,708
Other Comprehensive Income (Loss), Before Tax:			
Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(24,172)	(30,155)	(71,771)
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	8,536	5,000	1,008
Foreign Currency Translation Adjustment	51	53	(33)
Unrealized Loss on Securities Available for Sale Arising During the Period	(1,199)	(2,195)	(6,118)
Unrealized Gain on Derivative Financial Instruments Arising During the Period	30,238	65,366	119,210
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(15,485)	(41,320)	(114,380)
Other Comprehensive Loss, Before Tax	(2,031)	(3,251)	(72,084)
Income Tax Benefit Related to the Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(8,735)	(11,379)	(27,082)
Reclassification Adjustment for Income Tax Benefit Related to the Amortization of the Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	3,221	1,887	380
Income Tax Benefit Related to Unrealized Loss on Securities Available for Sale Arising During the Period	(453)	(831)	(2,311)
Income Tax Expense Related to Unrealized Gain on Derivative Financial Instruments Arising During the Period	12,836	26,628	48,293
Reclassification Adjustment for Income Tax Expense on Realized Gains on Derivative Financial Instruments in Net Income	(6,186)	(16,967)	(46,005)
Income Taxes Net	683	(662)	(26,725)
Other Comprehensive Loss	(2,714)	(2,589)	(45,359)
Comprehensive Income	$ 255,688	$ 223,324	$ 55,349

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A Summary of Significant Accounting Policies

Principles of Consolidation

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

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

Reclassification

Certain prior year amounts have been reclassified to conform with current year presentation. This includes the reclassification of accrued capital expenditures of $55.5 million from Accounts Payable to Other Accruals and Current Liabilities on the Consolidated Balance Sheet at September 30, 2010. This reclassification did not impact the Consolidated Statement of Income or the Consolidated Statement of Cash Flows for any of the periods presented.

Regulation

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

Revenue Recognition

The Company s Utility segment records revenue as bills are rendered, except that service supplied but not billed is reported as unbilled utility revenue and is included in operating revenues for the year in which service is furnished.

The Company s Energy Marketing segment records revenue as bills are rendered for service supplied on a monthly basis.

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

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

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Allowance for Uncollectible Accounts

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

Regulatory Mechanisms

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

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

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

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

In the Pipeline and Storage segment, the allowed rates that Supply Corporation and Empire bill their customers are based on a straight fixed-variable rate design, which allows recovery of all fixed costs, including return on equity and income taxes, through fixed monthly reservation charges. Because of this rate design, changes in throughput due to weather variations do not have a significant impact on the revenues of Supply Corporation or Empire. Prior to December 10, 2008, the date on which Empire became FERC regulated, the allowed rates that Empire billed its customers were based on a modified fixed-variable rate design, which recovered return on equity and income taxes through variable charges. Because of this rate design, changes in throughput due to weather variations could have had a significant impact on Empire s revenues.

Property, Plant and Equipment

The principal assets of the Utility and Pipeline and Storage segments, consisting primarily of gas plant in service, are recorded at the historical cost when originally devoted to service in the regulated businesses, as required by regulatory authorities.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

In March 2011, the Company entered into a purchase and sale agreement to sell its off-shore oil and natural gas properties in the Gulf of Mexico effective as of January 1, 2011 and completed the sale in April 2011. The Company received net proceeds of $55.4 million from this sale. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs in April 2011. The Company also eliminated the asset retirement obligation associated with its off-shore oil and gas properties. This obligation amounted to $37.5 million and was accounted for as a reduction of capitalized costs under the full cost method of accounting for oil and natural gas properties as well as a reduction of the asset retirement obligation. Asset retirement obligations are discussed further in Note B Asset Retirement Obligations.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2011, 2010, and 2009, estimated future net cash flows were increased by $35.4 million, $65.4 million and $143.3 million, respectively. The Company s capitalized costs exceeded the full cost ceiling for the Company s oil and gas properties at December 31, 2008. As such, the Company recognized a pre-tax impairment of $182.8 million at December 31, 2008 (utilizing period end pricing as required by the SEC full cost rules then in effect). Deferred income taxes of $74.6 million were recorded associated with this impairment.

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

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Depreciation, Depletion and Amortization

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

	As of September 30	
	2011	2010
	(Thousands)	
Utility	$ 1,695,702	$ 1,657,686
Pipeline and Storage	1,260,301	1,241,179
Exploration and Production	2,042,225	2,294,235
Energy Marketing	2,095	1,634
All Other and Corporate	144,738	127,939
	$ 5,145,061	$ 5,322,673

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2011	2010	2009
Utility	2.6%	2.6%	2.6%
Pipeline and Storage	3.1%	3.0%	3.0%
Exploration and Production, per Mcfe(1)	$ 2.17	$ 2.14	$ 2.14
Energy Marketing	2.5%	2.9%	3.4%
All Other and Corporate	1.2%	6.6%	5.2%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note O Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $2.12, $2.10 and $2.10 per Mcfe of production in 2011, 2010 and 2009, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2011 and 2010 on its Consolidated Balance Sheets related to the Company s acquisition of Empire in 2003. The Company accounts for goodwill in accordance with the current authoritative guidance, which requires the Company to test goodwill for impairment annually. At September 30, 2011, 2010 and 2009, the fair value of Empire was greater than its book value. As such, the goodwill was not considered impaired at those dates. Going back to the origination of the goodwill in 2003, the Company has never recorded an impairment of its goodwill balance.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Instruments

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

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments include price swap agreements and futures contracts. The Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled Fair Value of Derivative Financial Instruments. Reference is made to Note F Fair Value Measurements for further discussion concerning the fair value of derivative financial instruments.

For effective cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues or purchased gas expense on the Consolidated Statements of Income. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statements of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2011, 2010 or 2009.

For fair value hedges, the offset to the asset or liability that is recorded is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheets representing the change in fair value of the asset or firm commitment that is being hedged (see Other Current Assets section in this footnote). The offset to this asset or liability is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income as well. If the fair value hedge is effective, the gain or loss from the derivative financial instrument is offset by the gain or loss that arises from the change in fair value of the asset or firm commitment that is being hedged. The Company did not experience any material ineffectiveness with regard to its fair value hedges during 2011, 2010 or 2009.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) are as follows:

	Year Ended September 30	
	2011	**2010**
	(Thousands)	
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (89,587)	$ (79,465)
Cumulative Foreign Currency Translation Adjustment		(51)
Net Unrealized Gain on Derivative Financial Instruments	40,979	32,876
Net Unrealized Gain on Securities Available for Sale	909	1,655
Accumulated Other Comprehensive Loss	$ (47,699)	$ (44,985)

At September 30, 2011, it is estimated that of the $41.0 million net unrealized gain on derivative financial instruments (which are classified as cash flow hedges) shown in the table above, $27.7 million of unrealized gains will be reclassified into the Consolidated Statement of Income during 2012. The remaining unrealized gains on these instruments totaling $13.3 million will be reclassified into the Consolidated Statement of Income in subsequent years. These instruments extend out to 2014.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The amounts included in accumulated other comprehensive income (loss) related to the funded status of the Company s pension and other post-retirement benefit plans consist of prior service costs and accumulated losses. The total amount for prior service credit (cost) was $0.5 million and ($0.3) million at September 30, 2011 and 2010, respectively. The total amount for accumulated losses was $90.0 million and $79.2 million at September 30, 2011 and 2010, respectively.

Gas Stored Underground Current

In the Utility segment, gas stored underground current in the amount of $33.4 million is carried at lower of cost or market, on a LIFO method. Based upon the average price of spot market gas purchased in September 2011, including transportation costs, the current cost of replacing this inventory of gas stored underground current exceeded the amount stated on a LIFO basis by approximately $80.5 million at September 30, 2011. All other gas stored underground current, which is in the Energy Marketing segment, is carried at an average cost method, subject to lower of cost or market adjustments.

Unamortized Debt Expense

Costs associated with the issuance of debt by the Company are deferred and amortized over the lives of the related debt. Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment.

Income Taxes

The Company and its domestic subsidiaries file a consolidated federal income tax return. Investment tax credit, prior to its repeal in 1986, was deferred and is being amortized over the estimated useful lives of the related property, as required by regulatory authorities having jurisdiction.

Consolidated Statements of Cash Flows

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

At September 30, 2011, the Company accrued $63.5 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. The Company also accrued $7.3 million of capital expenditures in the Pipeline and Storage segment. In addition, the Company accrued $1.4 million of capital expenditures in the All Other category. These amounts were excluded from the Consolidated Statement of Cash Flows at September 30, 2011 since they represented non-cash investing activities at that date.

At September 30, 2010, the Company accrued $55.5 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2010 since it represented a non-cash investing activity at that date. These capital expenditures were paid during the quarter ended December 31, 2010 and have been included in the Consolidated Statement of Cash Flows for the year ended September 30, 2011.

At September 30, 2009, the Company accrued $9.1 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. The Company also accrued $0.7 million of capital expenditures in the All Other category related to the construction of the Midstream Covington Gathering System at September 30, 2009. These amounts were excluded from the Consolidated

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Statement of Cash Flows at September 30, 2009 since they represent non-cash investing activities at that date. These capital expenditures were paid during the quarter ended December 31, 2009 and have been included in the Consolidated Statement of Cash Flows for the year ended September 30, 2010.

At September 30, 2008, the Company accrued $16.8 million of capital expenditures related to the construction of the Empire Connector project. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represented a non-cash investing activity at that date. These capital expenditures were paid during the quarter ended December 31, 2008 and have been included in the Consolidated Statement of Cash Flows for the year ended September 30, 2009.

Hedging Collateral Deposits

This is an account title for cash held in margin accounts funded by the Company to serve as collateral for hedging positions. At September 30, 2011, the Company had hedging collateral deposits of $5.5 million related to its exchange-traded futures contracts and $14.2 million related to its over-the-counter crude oil swap agreements. At September 30, 2010, the Company had hedging collateral deposits of $10.1 million related to its exchange-traded futures contracts and $1.0 million related to its over-the-counter crude oil swap agreements. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instrument liability or asset balances.

Other Current Assets

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

	Year Ended September 30	
	2011	2010
	(Thousands)	
Prepayments	$ 9,489	$ 13,884
Prepaid Property and Other Taxes	13,240	12,413
Federal Income Taxes Receivable	385	56,334
State Income Taxes Receivable	6,124	18,007
Fair Values of Firm Commitments	9,096	15,331
	$ 38,334	$ 115,969

Customer Advances

The Company s Utility and Energy Marketing segments have balanced billing programs whereby customers pay their estimated annual usage in equal installments over a twelve-month period. Monthly payments under the balanced billing programs are typically higher than current month usage during the summer months. During the winter months, monthly payments under the balanced billing programs are typically lower than current month usage. At September 30, 2011 and 2010, customers in the balanced billing programs had advanced excess funds of $19.6 million and $27.6 million, respectively.

Customer Security Deposits

The Company, in its Utility, Pipeline and Storage, and Energy Marketing segments, often times requires security deposits from marketers, producers, pipeline companies, and commercial and industrial customers before providing services to such customers. At September 30, 2011 and 2010, the Company had received customer security deposits amounting to $17.3 million and $18.3 million, respectively.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options, SARs and restricted stock units. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. Stock options, SARs and restricted stock units that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2011, there were no securities excluded as being antidilutive. For 2010 and 2009, 314,910 securities and 1,130,000 securities were excluded as being antidilutive, respectively.

Stock-Based Compensation

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, SARs, restricted stock, restricted stock units, performance units or performance shares. Stock options and SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no stock option or SAR is exercisable less than one year or more than ten years after the date of each grant. Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. The market value of restricted stock on the date of the award is recorded as compensation expense over the vesting period. Certificates for shares of restricted stock awarded under the Company s stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant. Restricted stock units also are subject to restrictions on vesting and transferability. Restricted stock units represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. These restricted stock units do not entitle the participants to dividend and voting rights. The accounting for these restricted stock units is the same as the accounting for restricted share awards, except that the fair value at the date of grant of the restricted stock units (represented by the market value of Company common stock on the date of the award) must be reduced by the present value of forgone dividends over the vesting term of the award. The fair value of restricted stock units on the date of award is recorded as compensation expense over the vesting period.

The Company follows authoritative guidance which requires the measurement and recognition of compensation cost at fair value for all share-based payments, including stock options and SARs. The Company has chosen the Black-Scholes-Merton closed form model to calculate the compensation expense associated with such share-based payments since it is easier to administer than the Binomial option-pricing model. Furthermore, since the Company does not have complex stock-based compensation awards, it does not believe that compensation expense would be materially different under either model.

The Company granted 195,000 non-performance based SARs during the year ended September 30, 2011. The Company did not grant any non-performance based SARs during the years ended September 30, 2010 and 2009. These SARs may be settled in cash, in shares of common stock of the Company, or in a combination of cash and shares of common stock of the Company, as determined by the Company. These SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for non-performance based SARs is the same as the accounting for stock options. The non-performance based SARs granted during the year ended September 30, 2011 vest and become exercisable

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

annually in one-third increments. The weighted average grant date fair value of these non-performance based SARs granted during the year ended September 30, 2011 was estimated on the date of grant using the same accounting treatment that is applied for stock options.

The Company did not grant any performance based SARs during the year ended September 30, 2011. The Company granted 520,500 and 610,000 performance based SARs during the years ended September 30, 2010 and 2009, respectively. The accounting treatment for performance based SARS is the same as the accounting for stock options under the current authoritative guidance for stock-based compensation. The performance based SARs granted for the years ended September 30, 2010 and 2009 vest and become exercisable annually in one-third increments, provided that a performance condition is met. The performance condition for each fiscal year, generally stated, is an increase over the prior fiscal year of at least five percent in certain oil and natural gas production of the Exploration and Production segment. The weighted average grant date fair value of the performance based SARs granted during 2010 and 2009 was estimated on the date of grant using the same accounting treatment that is applied for stock options, and assumes that the performance conditions specified will be achieved. If such conditions are not met or it is not considered probable that such conditions will be met, no compensation expense is recognized and any previously recognized compensation expense is reversed. During 2009, the Company reversed $0.5 million of previously recognized compensation expense associated with performance based SARs.

The Company granted 47,250, 4,000, and 63,000 restricted share awards (non-vested stock as defined by the current accounting literature) during the years ended September 30, 2011, 2010 and 2009, respectively. In addition, the Company granted 41,800 restricted stock units during the year ended September 30, 2011.

Stock-based compensation expense for the years ended September 30, 2011, 2010 and 2009 was approximately $6.7 million, $4.4 million, and $2.1 million (net of the $0.5 million reversal of compensation expense discussed above), respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statements of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2011, 2010 and 2009 was approximately $2.7 million, $1.8 million and $0.8 million, respectively. There were no capitalized stock-based compensation costs during the years ended September 30, 2011, 2010 and 2009.

The Company realizes tax benefits related to the exercise of stock options and performance based SARs on a calendar year basis as opposed to a fiscal year basis. For stock options and performance based SARs exercised during the period of January 1, 2011 through September 30, 2011, the Company realized a tax benefit of approximately $11.2 million. This $11.2 million tax benefit will not be recorded in the quarter ended December 31, 2011 due to tax loss carryforwards.

For stock options exercised during the period of January 1, 2010 through September 30, 2010, the Company realized a tax benefit of approximately $13.3 million; and for stock options exercised during the quarter ended December 31, 2010, the Company realized a tax benefit of approximately $4.7 million. This tax benefit totaling $18.0 million was not recorded in the quarter ended December 31, 2010 due to tax loss carryforwards.

For stock options exercised during the period of January 1, 2009 through September 30, 2009, the Company realized a tax benefit of approximately $5.7 million; and for stock options exercised during the quarter ended December 31, 2009, the Company realized a tax benefit of approximately $6.5 million. This tax benefit totaling $12.2 million was recorded in the quarter ended December 31, 2009.

For stock options exercised during the period of January 1, 2008 through September 30, 2008, the Company realized a tax benefit of approximately $4.3 million; and for stock options exercised during the

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

quarter ended December 31, 2008, the Company realized a tax benefit of approximately $1.6 million. This tax benefit totaling $5.9 million was recorded in the quarter ended December 31, 2008.

Stock Options

The total intrinsic value of stock options exercised during the years ended September 30, 2011, 2010 and 2009 totaled approximately $44.6 million, $53.6 million, and $18.7 million, respectively. For 2011, 2010 and 2009, the amount of cash received by the Company from the exercise of such stock options was approximately $9.5 million, $34.5 million, and $29.2 million, respectively.

There were no stock options granted during the years ended September 30, 2011, 2010 and 2009. For the year ended September 30, 2011, no stock options became fully vested. For the years ended September 30, 2010 and 2009, 100,000 and 27,000 stock options became fully vested, respectively. The total fair value of the stock options that became vested during the years ended September 30, 2010 and 2009 was approximately $0.7 million and $0.2 million, respectively. As of September 30, 2011, there was no unrecognized compensation expense related to stock options. For a summary of transactions during 2011 involving option shares for all plans, refer to Note E Capitalization and Short-Term Borrowings.

Non-Performance Based SARs

Participants in the stock option and award plans did not exercise any non-performance based SARs during the years ended September 30, 2011, 2010 and 2009. As stated above, there were 195,000 non-performance based SARs granted during the year ended September 30, 2011. The Company did not grant any non-performance based SARs during the years ended September 30, 2010 and 2009. The weighted average grant date fair value of non-performance based SARs granted in 2011 is $15.01. For the year ended September 30, 2011, no non-performance based SARs became fully vested. For the year ended September 30, 2010, 50,000 non-performance based SARs became fully vested. Fiscal 2010 was the first year in which non-performance based SARs became vested. The total fair value of the non-performance based SARs that became vested during the year ended September 30, 2010 was approximately $0.4 million. As of September 30, 2011, unrecognized compensation expense related to non-performance based SARs totaled approximately $1.5 million, which will be recognized over a weighted average period of 11.9 months. For a summary of transactions during 2011 involving non-performance based SARs for all plans, refer to Note E Capitalization and Short-Term Borrowings.

The fair value of non-performance based SARs at the date of grant was estimated using the Black-Scholes-Merton closed form model. The following weighted average assumptions were used in estimating the fair value of non-performance based SARs at the date of grant:

	Year Ended September 30, 2011
Risk Free Interest Rate	2.94%
Expected Life (Years)	8.00
Expected Volatility	23.38%
Expected Dividend Yield (Quarterly)	0.55%

The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the performance based SARs. The expected life and expected volatility are based on historical experience.

For grants during the year ended September 30, 2011, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Performance Based SARs

The total intrinsic value of performance based SARs exercised during the year ended September 30, 2011 totaled approximately $0.3 million. Participants in the stock option and award plans did not exercise any performance based SARs during the years ended September 30, 2010 and 2009. As stated above, the Company did not grant any performance based SARs during the year ended September 30, 2011. There were 520,500 and 610,000 performance based SARs granted during the years ended September 30, 2010 and 2009, respectively. The weighted average grant date fair value of performance based SARs granted in 2010 and 2009 is $12.06 per share and $4.09 per share, respectively. For the years ended September 30, 2011, 2010 and 2009, 388,986, 203,324 and 96,984 performance based SARs became fully vested. The total fair value of the performance based SARs that became vested during each of the years ended September 30, 2011, 2010 and 2009 was approximately $3.1 million, $0.8 million and $0.8 million, respectively. As of September 30, 2011, unrecognized compensation expense related to performance based SARs totaled approximately $1.1 million, which will be recognized over a weighted average period of 7.1 months. For a summary of transactions during 2011 involving performance based SARs for all plans, refer to Note E Capitalization and Short-Term Borrowings.

The fair value of performance based SARs at the date of grant was estimated using the Black-Scholes-Merton closed form model. The following weighted average assumptions were used in estimating the fair value of performance based SARs at the date of grant:

	Year Ended September 30	
	2010	**2009**
Risk Free Interest Rate	3.55%	2.56%
Expected Life (Years)	7.75	7.50
Expected Volatility	23.25%	22.16%
Expected Dividend Yield (Quarterly)	0.64%	1.09%

The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the performance based SARs. The expected life and expected volatility are based on historical experience.

For grants during the years ended September 30, 2010 and 2009, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

Restricted Share Awards

The weighted average fair value of restricted share awards granted in 2011, 2010 and 2009 is $63.98 per share, $52.10 per share and $47.46 per share, respectively. As of September 30, 2011, unrecognized compensation expense related to restricted share awards totaled approximately $4.5 million, which will be recognized over a weighted average period of 2.8 years. For a summary of transactions during 2011 involving restricted share awards, refer to Note E Capitalization and Short-Term Borrowings.

Restricted Stock Units

The weighted average fair value of restricted share units granted in 2011 is $59.35 per share. As of September 30, 2011, unrecognized compensation expense related to restricted share awards totaled approximately $2.0 million, which will be recognized over a weighted average period of 2.2 years. For a summary of transactions during 2011 involving restricted share awards, refer to Note E Capitalization and Short-Term Borrowings.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

New Authoritative Accounting and Financial Reporting Guidance

In May 2011, the FASB issued authoritative guidance regarding fair value measurement as a joint project with the IASB. The objective of the guidance was to bring together as closely as possible the fair value measurement and disclosure guidance issued by the two boards. The guidance includes a few updates to measurement guidance and some enhanced disclosure requirements. For all Level 3 fair value measurements, the guidance requires quantitative information about significant unobservable inputs used and a description of the valuation processes in place. The guidance also requires a qualitative discussion about the sensitivity of recurring Level 3 fair value measurements and information about any transfers between Level 1 and Level 2 of the fair value hierarchy. The new guidance also contains a requirement that all fair value measurements, whether they are recorded on the balance sheet or disclosed in the footnotes, be classified as Level 1, Level 2 or Level 3 within the fair value hierarchy. This authoritative guidance will be effective as of the Company s second quarter of fiscal 2012. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statement disclosures.

In June 2011, the FASB issued authoritative guidance regarding the presentation of comprehensive income. The new guidance allows companies only two choices for presenting net income and other comprehensive income: in a single continuous statement, or in two separate, but consecutive, statements. The guidance eliminates the current option to report other comprehensive income and its components in the statement of changes in equity. This authoritative guidance will be effective as of the Company s first quarter of fiscal 2013 and is not expected to have a significant impact on the Company s financial statements.

In September 2011, the FASB issued revised authoritative guidance that simplifies the testing of goodwill for impairment. The revised guidance allows companies the option to perform a qualitative assessment to determine whether further impairment testing is necessary. The revised authoritative guidance is required to be effective for the Company s annual impairment test performed in fiscal 2013. However, early adoption is permitted. The Company did not use the revised authoritative guidance in performing its annual impairment test for fiscal 2011.

Note B Asset Retirement Obligations

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The full cost method of accounting provides a limit to the amount of costs that can be capitalized in the full cost pool. This limit is referred to as the full cost ceiling. In accordance with current authoritative guidance, since the full cost pool includes an amount associated with plugging and abandoning the wells, as discussed in the preceding paragraph, the calculation of the full cost ceiling no longer reduces the future net cash flows from proved oil and gas reserves by an estimate of plugging and abandonment costs.

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

A reconciliation of the Company s asset retirement obligation is shown below:

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
Balance at Beginning of Year	$ 101,618	$ 91,373	$ 93,247
Liabilities Incurred and Revisions of Estimates	10,346	16,140	4,492
Liabilities Settled	(41,704)	(12,622)	(13,155)
Accretion Expense	5,471	6,727	6,789
Balance at End of Year	$ 75,731	$ 101,618	$ 91,373

Note C Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2011	2010
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note H)	$ 333,219	$ 308,822
Post-Retirement Benefit Costs(2) (Note H)	174,768	159,498
Recoverable Future Taxes (Note D)	144,377	149,712
Environmental Site Remediation Costs(2) (Note I)	20,095	20,491
NYPSC Assessment(2)	15,063	19,229
Asset Retirement Obligations(2) (Note B)	13,860	12,529
Unamortized Debt Expense (Note A)	5,090	5,727
Other(2)	17,639	22,232

Total Regulatory Assets	724,111	698,240

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	At September 30	
	2011	2010
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	135,940	124,032
Taxes Refundable to Customers (Note D)	65,543	69,585
Post-Retirement Benefit Costs(3) (Note H)	50,409	42,461
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	15,519	38,109
Pension Costs(3) (Note H)	13,313	16,171
Off-System Sales and Capacity Release Credits(3)	7,675	11,594
Other(3)	23,287	19,108
Total Regulatory Liabilities	311,686	321,060
Net Regulatory Position	$ 412,425	$ 377,180

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

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

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

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

Cost of Removal Regulatory Liability

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

NYPSC Assessment

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Off-System Sales and Capacity Release Credits

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

Note D Income Taxes

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

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
Current Income Taxes			
Federal	$ (1,390)	$ 2,074	$ 43,300
State	1,520	4,991	10,341
Deferred Income Taxes			
Federal	130,434	110,515	(4,940)
State	33,817	24,164	2,419
	164,381	141,744	51,120
Deferred Investment Tax Credit	(697)	(697)	(697)
Total Income Taxes	$ 163,684	$ 141,047	$ 50,423
Presented as Follows:			
Other Income	$ (697)	$ (697)	$ (697)
Income Tax Expense Continuing Operations	164,381	137,227	52,859
Discontinued Operations			
Income (Loss) from Operations		493	(1,739)
Gain on Disposal		4,024	
Total Income Taxes	$ 163,684	$ 141,047	$ 50,423

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

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
U.S. Income Before Income Taxes	$ 422,086	$ 366,960	$ 151,131
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$ 147,730	$ 128,436	$ 52,896
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	22,969	18,951	8,294

Miscellaneous	(7,015)	(6,340)	(10,767)
Total Income Taxes	$ 163,684	$ 141,047	$ 50,423

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	At September 30	
	2011	2010
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 1,062,255	$ 849,869
Pension and Other Post-Retirement Benefit Costs	217,302	177,853
Other	70,389	63,671
Total Deferred Tax Liabilities	1,349,946	1,091,393
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(263,606)	(223,588)
Tax Loss Carryforwards	(71,516)	(9,772)
Other	(74,863)	(81,751)
Total Deferred Tax Assets	(409,985)	(315,111)
Total Net Deferred Income Taxes	$ 939,961	$ 776,282
Presented as Follows:		
Net Deferred Tax Liability/(Asset) Current	$ (15,423)	$ (24,476)
Net Deferred Tax Liability Non-Current	955,384	800,758
Total Net Deferred Income Taxes	$ 939,961	$ 776,282

As a result of certain realization requirements of the authoritative guidance on stock-based compensation, the table of deferred tax liabilities and assets shown above does not include certain deferred tax assets at September 30, 2011 that arose directly from excess tax deductions related to stock-based compensation. A tax benefit of $18.0 million relating to the excess stock-based compensation deductions will be recorded in Paid in Capital in future years when such tax benefit is realized.

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $65.5 million and $69.6 million at September 30, 2011 and 2010, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $144.4 million and $149.7 million at September 30, 2011 and 2010, respectively. Included in the above are regulatory liabilities and assets relating to the tax accounting method change noted below. The amounts are as follows: regulatory liabilities of $47.3 million as of September 30, 2011 and 2010, and regulatory assets of $60.5 million and $56.3 million as of September 30, 2011 and 2010, respectively.

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

	Year Ended September 30		
	2011	2010	2009
	(Thousands)		

Balance at Beginning of Year	$ 8,490	$ 8,721	$ 1,700
Additions for Tax Positions Related to Current Year	80	699	8,721
Additions for Tax Positions of Prior Years	107	45	
Reductions for Tax Positions of Prior Years	(911)	(975)	
Settlements with Taxing Authorities			(1,700)
Lapse of Statute of Limitations			
Balance at End of Year	$ 7,766	$ 8,490	$ 8,721

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

If the amount of unrecognized tax benefits recorded as of September 30, 2011 were recognized, there would not be a material impact on the effective tax rate. The unrecognized tax benefits relate entirely to the Company s tax accounting method change noted below. The Company anticipates that during the next 12 months there will be additional Internal Revenue Service (IRS) guidance in this area and the IRS Appeals process will be resolved, thus eliminating the unrecognized tax benefits.

The Company recognizes interest relating to income taxes in Other Interest Expense and penalties relating to income taxes in Other Income. The Company recognized interest expense relating to income taxes of $0.3 million, $0.3 million and $0.0 million for fiscal 2011, 2010 and 2009, respectively. The Company has not accrued any penalties during fiscal 2011, 2010 and 2009.

The Company files U.S. federal and various state income tax returns. The IRS is currently conducting an examination of the Company for fiscal 2010 and fiscal 2011 in accordance with the Compliance Assurance Process (CAP). The CAP audit employs a real time review of the Company s books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. While the federal statute of limitations remains open for fiscal 2008 and later years, IRS examinations for fiscal 2008 and prior years have been completed and the Company believes such years are effectively settled. During fiscal 2009, consent was received from the IRS National Office approving the Company s application to change its tax method of accounting for certain capitalized costs relating to its utility property. During fiscal 2010, local IRS examiners proposed to disallow most of the tax accounting method change recorded by the Company in fiscal 2009. The Company has filed a protest with the IRS Appeals Office disputing the local IRS findings. During fiscal 2011, local IRS examiners proposed to disallow most of the tax accounting method change recorded by the Company in fiscal 2010. The Company is planning to appeal this proposed disallowance.

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

As of September 30, 2011, the Company has a federal net operating loss (NOL) carryover of $221 million, which expires in varying amounts between 2023 and 2031. Approximately $23 million of this NOL is subject to certain annual limitations, and $48 million is attributable to excess tax deductions related to stock based compensation as discussed above. In addition, the Company has state NOL carryovers in Pennsylvania, California and New York of $129 million, $62 million and $38 million, respectively, which begin to expire in varying amounts between 2029 and 2031. No valuation allowance was recorded on the federal or state NOL carryovers because of management s determination that the amounts will be fully utilized during the carryforward period.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note E Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock			Earnings Reinvested	Accumulated Other Comprehensive
	Shares	Amount	Paid In Capital	in the Business	Income (Loss)
	(Thousands, except per share amounts)				
Balance at September 30, 2008	79,121	$ 79,121	$ 567,716	$ 953,799	$ 2,963
Net Income Available for Common Stock				100,708	
Dividends Declared on Common Stock ($1.32 Per Share)				(105,410)	
Adoption of Authoritative Guidance for Defined Benefit Pension and Other Post-Retirement Plans				(804)	
Other Comprehensive Loss, Net of Tax					(45,359)
Share-Based Payment Expense(2)			2,055		
Common Stock Issued Under Stock and Benefit Plans(1)	1,379	1,379	33,068		
Balance at September 30, 2009	80,500	80,500	602,839	948,293	(42,396)
Net Income Available for Common Stock				225,913	
Dividends Declared on Common Stock ($1.36 Per Share)				(110,944)	
Other Comprehensive Loss, Net of Tax					(2,589)
Share-Based Payment Expense(2)			4,435		
Common Stock Issued Under Stock and Benefit Plans(1)	1,575	1,575	38,345		
Balance at September 30, 2010	82,075	82,075	645,619	1,063,262	(44,985)
Net Income Available for Common Stock				258,402	
Dividends Declared on Common Stock ($1.40 Per Share)				(115,642)	
Other Comprehensive Loss, Net of Tax					(2,714)
Share-Based Payment Expense(2)			6,656		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans(1)	738	738	(1,526)		
Balance at September 30, 2011	82,813	$ 82,813	$ 650,749	$ 1,206,022(3)	$ (47,699)

(1) Paid in Capital includes tax costs of $1.2 million for September 30, 2011 and tax benefits of $13.2 million and $5.9 million for September 30, 2010 and 2009, respectively, associated with the exercise of stock options.

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

(3) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2011, $1.1 billion of accumulated earnings was free of such limitations.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Common Stock

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends and make cash investments in the Company s common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, at the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent. During 2011, the Company issued 55,113 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan.

During 2011, the Company issued 1,123,164 original issue shares of common stock as a result of stock option and SARs exercises and 47,250 original issue shares for restricted stock awards (non-vested stock as defined by the current accounting literature for stock-based compensation). Holders of stock options, SARs or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During 2011, 503,620 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

The Company also has a director stock program under which it issues shares of Company common stock to the non-employee directors of the Company who receive compensation under the Company s 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors services during the fiscal year. Under this program, the Company issued 15,300 original issue shares of common stock during 2011.

Shareholder Rights Plan

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

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

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

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

A Distribution Date would occur upon the earlier of (i) ten days after the public announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of the Company s common stock or other voting stock (including Synthetic Long Positions as defined in the Plan) having 10%

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

or more of the total voting power of the Company s common stock and other voting stock and (ii) ten days after the commencement or announcement by a person or group of an intention to make a tender or exchange offer that would result in that person acquiring, or obtaining the right to acquire, beneficial ownership of the Company s common stock or other voting stock having 10% or more of the total voting power of the Company s common stock and other voting stock.

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

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

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

Stock Option and Stock Award Plans

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

	Number of Shares Subject to Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2010	2,879,247	$ 29.30		
Granted in 2011		$		
Exercised in 2011	(1,119,980)	$ 26.04		
Forfeited in 2011	(306)	$ 24.50		
Outstanding at September 30, 2011	1,758,961	$ 31.38	2.93	$ 30,436
Option shares exercisable at September 30, 2011	1,758,961	$ 31.38	2.93	$ 30,436
Option shares available for future grant at September 30, 2011(1)	2,515,703			

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

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Transactions involving non-performance based SARs for all plans are summarized as follows:

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2010	50,000	$ 41.20		
Granted in 2011	195,000	$ 63.30		
Exercised in 2011		$		
Forfeited in 2011		$		
Outstanding at September 30, 2011	245,000	$ 58.79	8.50	$ (2,478)
SARs exercisable at September 30, 2011	50,000	$ 41.20	5.45	$ 374

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

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2010	1,348,493	$ 41.49		
Granted in 2011		$		
Exercised in 2011	(10,997)	$ 38.63		
Forfeited in 2011	(7,334)	$ 55.86		
Canceled in 2011(1)	(105,009)	$ 48.26		
Outstanding at September 30, 2011	1,225,153	$ 40.85	7.67	$ 9,592
SARs exercisable at September 30, 2011	666,130	$ 38.07	7.42	$ 7,068

(1) Shares were canceled during 2011 due to performance condition not being met.

Restricted Share Awards

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

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Restricted Share Awards Outstanding at September 30, 2010	94,500	$ 47.57
Granted in 2011	47,250	$ 63.98
Vested in 2011	(2,500)	$ 34.94
Forfeited in 2011		$
Restricted Share Awards Outstanding at September 30, 2011	139,250	$ 53.37

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2011 will lapse as follows: 2012 18,740 shares; 2013 20,750 shares; 2014 20,760 shares; 2015 19,000 shares; 2016 5,000 shares; 2018 35,000 shares; and 2021 20,000 shares.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Restricted Stock Units

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

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Restricted Stock Units Outstanding at September 30, 2010		$
Granted in 2011	41,800	$ 59.35
Vested in 2011		$
Forfeited in 2011	(2,400)	$ 61.87
Restricted Stock Units Outstanding at September 30, 2011	39,400	$ 59.20

Vesting restrictions for the outstanding shares of non-vested restricted stock units at September 30, 2011 will lapse as follows: 2014 13,132 shares; 2015 13,134 shares; and 2016 13,134 shares.

Redeemable Preferred Stock

As of September 30, 2011, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

Long-Term Debt

The outstanding long-term debt is as follows:

	At September 30 2011	2010
	(Thousands)	
Medium-Term Notes(1):		
6.7% to 7.50% due November 2010 to June 2025	$ 249,000	$ 449,000
Notes(1):		
5.25% to 8.75% due March 2013 to May 2019	800,000	800,000
Total Long-Term Debt	1,049,000	1,249,000
Less Current Portion(2)	150,000	200,000
	$ 899,000	$ 1,049,000

(1) The Medium-Term Notes and Notes are unsecured.

(2) Current Portion of Long-Term Debt at September 30, 2011 consists of $150.0 million of 6.70% medium-term notes that matured in November 2011. Current Portion of Long-Term Debt at September 30, 2010 consists of $200.0 million of 7.50% medium-term notes that matured in November 2010.

The Company has $300.0 million of 6.50% notes that mature in April 2018 and $250.0 million of 8.75% notes that mature in May 2019. The holders of these notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade.

As of September 30, 2011, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $150.0 million in 2012, $250.0 million in 2013, zero in 2014, zero in 2015, zero in 2016 and $649.0 million thereafter.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. As for the former, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $385.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or substantially replaced by similar lines. The total amount available to be issued under the Company s commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million, which commitment extends through September 30, 2013.

At September 30, 2011, the Company had $40.0 million in outstanding commercial paper. The weighted average interest rate on this commercial paper was 0.43%. The Company did not have any outstanding short-term notes payable to banks or commercial paper at September 30, 2010.

Debt Restrictions

Under the Company s committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2013. At September 30, 2011, the Company s debt to capitalization ratio (as calculated under the facility) was .37. The constraints specified in the committed credit facility would permit an additional $2.42 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company s debt to capitalization ratio would exceed .65. If a downgrade in any of the Company s credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company s existing indenture covenants, at September 30, 2011, the Company would have been permitted to issue up to a maximum of $1.77 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company s present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company s ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt.

The Company s 1974 indenture pursuant to which $99.0 million (or 9.4%) of the Company s long-term debt (as of September 30, 2011) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company s $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2011, the Company had no debt outstanding under the committed credit facility.

Note F Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of September 30, 2011 and 2010. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Recurring Fair Value Measures	At Fair Value as of September 30, 2011 Level 1	Level 2	Level 3	Total
		(Dollars in thousands)		
Assets:				
Cash Equivalents Money Market Mutual Funds	$ 32,444	$	$	$ 32,444
Derivative Financial Instruments:				
Over the Counter Swaps Gas		75,113		75,113
Over the Counter Swaps Oil			972	972
Other Investments:				
Balanced Equity Mutual Fund	19,882			19,882
Common Stock Financial Services Industry	4,478			4,478
Other Common Stock	226			226
Hedging Collateral Deposits	19,701			19,701
Total	$ 76,731	$ 75,113	$ 972	$ 152,816
Liabilities:				
Derivative Financial Instruments:				
Commodity Futures Contracts Gas	$ 3,292	$	$	$ 3,292
Over the Counter Swaps Oil			6,382	6,382
Total	$ 3,292	$	$ 6,382	$ 9,674
Total Net Assets/(Liabilities)	$ 73,439	$ 75,113	$ (5,410)	$ 143,142

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Recurring Fair Value Measures	At Fair Value as of September 30, 2010 Level 1	Level 2	Level 3	Total
		(Dollars in thousands)		
Assets:				
Cash Equivalents Money Market Mutual Funds	$ 277,423	$	$	$ 277,423
Derivative Financial Instruments:				
Over the Counter Swaps Gas		67,387		67,387
Over the Counter Swaps Oil			(2,203)	(2,203)
Other Investments:				
Balanced Equity Mutual Fund	17,256			17,256
Common Stock Financial Services Industry	4,991			4,991
Other Common Stock	241			241
Hedging Collateral Deposits	11,134			11,134
Total	$ 311,045	$ 67,387	$ (2,203)	$ 376,229
Liabilities:				
Derivative Financial Instruments:				
Commodity Futures Contracts Gas	$ 5,840	$	$	$ 5,840
Over the Counter Swaps Oil			14,280	14,280
Over the Counter Swaps Gas		40		40
Total	$ 5,840	$ 40	$ 14,280	$ 20,160
Total Net Assets/(Liabilities)	$ 305,205	$ 67,347	$ (16,483)	$ 356,069

Derivative Financial Instruments

At September 30, 2011 and 2010, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX futures contracts used in the Company s Energy Marketing segment. Hedging collateral deposits of $5.5 million (at September 30, 2011) and $10.1 million (at September 30, 2010), which are associated with these futures contracts have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at September 30, 2011 and 2010, consist of natural gas price swap agreements used in the Company s Exploration and Production and Energy Marketing segments. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The derivative financial instruments reported in Level 3 consist of the Company s Exploration and Production segment s crude oil price swap agreements at September 30, 2011 and 2010. Hedging collateral deposits of $14.2 million and $1.0 million associated with these crude oil price swap agreements have been reported in Level 1 at September 30, 2011 and September 30, 2010, respectively. The fair value of the Level 3 crude oil price swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume). Based on an assessment of the counterparties credit risk, the fair market value of the price swap agreements reported as Level 2 and Level 3 assets have been reduced by $2.0 million at September 30, 2011 and the fair market value of the price swap agreements reported as Level 2 assets have been reduced by $1.0 million at September 30, 2010. Based on an assessment of the Company s credit risk, the fair market value of the price swap agreements reported as Level 3 liabilities have not been reduced at September 30, 2011 and the fair market value of the price swap agreements reported as Level 2 and Level 3 liabilities have been reduced by $0.3 million at September 30, 2010. These credit reserves were determined by applying default probabilities to the anticipated cash flows that the Company is either expecting from its counterparties or expecting to pay to its counterparties.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the years ended September 30, 2011 and September 30, 2010, respectively. For the years ended September 30, 2011 and September 30, 2010, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the periods presented in the tables below. All settlements of the derivative financial instruments are reflected in the Gains/Losses Realized and Included in Earnings column of the tables below.

Fair Value Measurements Using Unobservable Inputs (Level 3)

		Total Gains/Losses			
	October 1, 2010	Gain/Losses Realized and Included in Earnings	Gains/Losses Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2011
			(Dollars in thousands)		
Derivative Financial Instruments(2)	$ (16,483)	$ 41,354(1)	$ (30,281)	$	$ (5,410)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2011.

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

Fair Value Measurements Using Unobservable Inputs (Level 3)

		Total Gains/Losses			
	October 1, 2009	Gain/Losses Realized and Included in Earnings	Gains/Losses Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2010
			(Dollars in thousands)		
Derivative Financial Instruments(2)	$ 26,969	$ (9,372)(1)	$ (34,080)	$	$ (16,483)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2010.

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

Note G Financial Instruments

Long-Term Debt

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

	At September 30			
	2011 Carrying Amount	2011 Fair Value	2010 Carrying Amount	2010 Fair Value
	(Thousands)			
Long-Term Debt	$ 1,049,000	$ 1,198,585	$ 1,249,000	$ 1,423,349

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay. Carrying amounts for other financial instruments recorded on the Company s Consolidated Balance Sheets approximate fair value.

Temporary cash investments, notes payable to banks and commercial paper are stated at cost, which approximates their fair value due to short-term maturities of those financial instruments.

Other Investments

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

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance contracts amounted to $54.8 million and $55.4 million at September 30, 2011 and 2010, respectively. The fair value of the equity mutual fund was $19.9 million and $17.3 million at September 30, 2011 and 2010, respectively. The gross unrealized loss on this equity mutual fund was $0.7 million at September 30, 2011. The unrealized gain on the equity mutual fund at September 30, 2010 was negligible as the fair market value was approximately equal to the cost basis. The fair value of the stock of an insurance company was $4.5 million and $5.0 million at September 30, 2011 and 2010, respectively. The gross unrealized gain on this stock was $2.1 million and $2.6 million at September 30, 2011 and 2010, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

The Company uses derivative instruments to manage commodity price risk in the Exploration and Production and Energy Marketing segments. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. The Company also enters into futures contracts and swaps to manage the risk associated with forecasted gas purchases, storage of gas, withdrawal of gas from storage to meet customer demand and the potential decline in the value of gas held in storage. The duration of the majority of the Company s hedges do not typically exceed 3 years.

The Company has presented its net derivative assets and liabilities on its Consolidated Balance Sheet at September 30, 2011 and September 30, 2010 as shown in the table below.

Derivatives Designated as Hedging Instruments	**Fair Values of Derivative Instruments (Dollar Amounts in Thousands)**			
	Asset Derivatives		**Liability Derivatives**	
	Consolidated Balance Sheet Location	**Fair Value**	**Consolidated Balance Sheet Location**	**Fair Value**
Commodity Contracts at September 30, 2011	Fair Value of Derivative Financial Instruments	$ 76,085	Fair Value of Derivative Financial Instruments	$ 9,674
Commodity Contracts at September 30, 2010	Fair Value of Derivative Financial Instruments	$ 65,184	Fair Value of Derivative Financial Instruments	$ 20,160

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table discloses the fair value of derivative contracts on a gross-contract basis as opposed to the net-contract basis presentation on the Consolidated Balance Sheets at September 30, 2011 and September 30, 2010.

Derivatives Designated as Hedging Instruments	Fair Values of Derivative Instruments (Dollar Amounts in Thousands)	
	Gross Asset Derivatives	Gross Liability Derivatives
Commodity Contracts at September 30, 2011	$ 90,253	$ 23,842
Commodity Contracts at September 30, 2010	$ 77,837	$ 32,813

Cash Flow Hedges

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

As of September 30, 2011, the Company s Exploration and Production segment had the following commodity derivative contracts (swaps) outstanding to hedge forecasted sales (where the Company uses short positions (i.e. positions that pay-off in the event of commodity price decline) to mitigate the risk of decreasing revenues and earnings):

Commodity	Units
Natural Gas	63.4 Bcf (all short positions)
Crude Oil	2,736,000 Bbls (all short positions)

As of September 30, 2011, the Company s Energy Marketing segment had the following commodity derivative contracts (futures contracts and swaps) outstanding to hedge forecasted sales (where the Company uses short positions to mitigate the risk associated with natural gas price decreases and its impact on decreasing revenues and earnings) and purchases (where the Company uses long positions (i.e. positions that pay-off in the event of commodity price increases) to mitigate the risk of increasing natural gas prices, which would lead to increased purchased gas expense and decreased earnings):

Commodity	Units
Natural Gas	7.1 Bcf (6.5 Bcf short positions (forecasted storage withdrawals) and 0.6 Bcf long positions (forecasted storage injections))

As of September 30, 2011, the Company s Exploration and Production segment had $67.4 million ($39.2 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $44.5 million ($25.9 million after tax) of these gains will be reclassified into the Consolidated Statement of Income (Loss) within the next 12 months as the expected sales of the underlying commodities occur. See Note A, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain (loss) pertaining to derivative financial instruments for both the Exploration and Production and Energy Marketing segment.

As of September 30, 2011, the Company s Energy Marketing segment had $2.9 million ($1.8 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that the full amount will be reclassified into the Consolidated

Statement of Income (Loss) within

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the next 12 months as the sales and purchases of the underlying commodities occur. See Note A, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain (loss) pertaining to derivative financial instruments for both the Exploration and Production and Energy Marketing segment.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2011 and 2010 (Dollar Amounts in Thousands)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Year Ended September 30, 2011	2010	Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Year Ended September 30, 2011	2010	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Year Ended September 30, 2011	2010
Commodity Contracts Exploration & Production segment	$ 24,713	$ 52,786	Operating Revenue	$ 6,367	$ 39,898	Operating Revenue	$	$
Commodity Contracts Energy Marketing segment	$ 5,015	$ 11,200	Purchased Gas	$ 8,608	$ 52	Operating Revenue	$	$
Commodity Contracts Pipeline & Storage segment(1)	$ 510	$ 1,380	Operating Revenue	$ 510	$ 1,370	Operating Revenue	$	$
Total	$ 30,238	$ 65,366		$ 15,485	$ 41,320		$	$

(1) There were no open hedging positions at September 30, 2011 or 2010. As such there is no mention of these positions in the preceding sections of this footnote.

Fair value hedges

The Company s Energy Marketing segment utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in the value of natural gas held in storage. With respect to fixed price sales commitments, the Company enters into long positions to mitigate the risk of price increases for natural gas supplies that could occur after the Company enters into fixed price sales agreements with its customers. With respect to fixed price purchase commitments, the Company enters into short positions to mitigate the risk of price decreases that could occur after the Company locks into fixed price purchase deals with its suppliers. With respect to storage hedges, the Company enters into short positions to mitigate the risk of price decreases that could result in a lower of cost or market writedown of the value of natural gas in storage that is recorded in the Company s financial

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

statements. As of September 30, 2011, the Company s Energy Marketing segment had fair value hedges covering approximately 10.9 Bcf (8.5 Bcf of fixed price sales commitments (all long positions) and 2.4 Bcf of fixed price purchase commitments (all short positions)). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Consolidated Statement of Income	Gain/(Loss) on Derivative		Gain/(Loss) on Commitment	
Operating Revenues	$	5,469,702	$	(5,469,702)
Purchased Gas	$	208,962	$	(208,962)

Derivatives in Fair Value Hedging Relationships Energy Marketing segment	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income	Amount of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income for the Year Ended September 30, 2011 (In thousands)	
Commodity Contracts Hedge of fixed price sales commitments of natural gas	Operating Revenues	$	5,470
Commodity Contracts Hedge of fixed price purchase commitments of natural gas	Purchased Gas		(303)
Commodity Contracts Hedge of natural gas held in storage	Purchased Gas		512
		$	**5,679**

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company s counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with eleven counterparties of which ten are in a net gain position. On average, the Company had $7.6 million of credit exposure per counterparty in a gain position at September 30, 2011. The maximum credit exposure per counterparty in a gain position at September 30, 2011 was $12.2 million. The Company had not received any collateral from these counterparties at September 30, 2011 since the Company s gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties credit ratings declined to levels at which the counterparties were required to post collateral.

As of September 30, 2011, eight of the eleven counterparties to the Company s outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company s credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company s credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company s outstanding derivative instrument contracts were in a liability position (or if the current liability were larger) and/or the Company s credit rating declined, then additional hedging collateral deposits would be required. At September 30, 2011, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $51.1 million according to the Company s internal model (discussed in Note F Fair Value Measurements). At September 30, 2011, the fair market value of the

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

derivative financial instrument liability with a credit-risk related contingency feature was $6.4 million according to the Company s internal model (discussed in Note F Fair Value Measurements). For its over-the-counter crude oil swap agreements, which are in a liability position, the Company was required to post $14.2 million in hedging collateral deposits at September 30, 2011. This is discussed in Note A under Hedging Collateral Deposits.

For its exchange traded futures contracts which are in a liability position, the Company had posted $5.5 million in hedging collateral as of September 30, 2011. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

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

Note H Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan) that covers a majority of the full-time employees of the Company. The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Certain non-collectively bargained employees hired after June 30, 2003 and certain collectively bargained employees hired after October 31, 2003 are eligible for a Retirement Savings Account benefit provided under the Company s defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account were $0.7 million, $0.6 million and $0.4 million for the years ended September 30, 2011, 2010 and 2009, respectively. Costs associated with the Company s contributions to the Tax-Deferred Savings Plans, exclusive of the costs associated with the Retirement Savings Account, were $4.3 million, $4.2 million, and $4.1 million for the years ended September 30, 2011, 2010 and 2009, respectively.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The expected return on plan assets, a component of net periodic benefit cost shown in the tables below, is applied to the market-related value of plan assets. The market-related value of plan assets is the market value as of the measurement date adjusted for variances between actual returns and expected returns (from previous years) that have not been reflected in net periodic benefit costs.

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and other post-retirement benefits are shown in the tables below. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is September 30 for fiscal year 2011, 2010 and 2009.

	Retirement Plan Year Ended September 30			Other Post-Retirement Benefits Year Ended September 30		
	2011	2010	2009	2011	2010	2009
			(Thousands)			
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 924,493	$ 831,496	$ 719,059	$ 472,407	$ 467,295	$ 411,545
Service Cost	14,772	12,997	10,913	4,276	4,298	3,801
Interest Cost	42,676	44,308	46,836	21,884	25,017	27,499
Plan Participants Contributions				1,963	1,644	2,185
Retiree Drug Subsidy Receipts				1,532	1,354	1,427
Amendments(1)	(1,764)			(7,187)		(10,765)
Actuarial (Gain) Loss	21,395	85,831	102,430	15,071	(3,635)	55,776
Adjustment for Change in Measurement Date			14,438			7,825
Benefits Paid	(51,795)	(50,139)	(62,180)	(24,494)	(23,566)	(31,998)
Benefit Obligation at End of Period	$ 949,777	$ 924,493	$ 831,496	$ 485,452	$ 472,407	$ 467,295
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 597,549	$ 563,881	$ 695,089	$ 353,269	$ 319,022	$ 377,640
Actual Return on Plan Assets	2,412	61,625	(99,511)	(4,094)	30,478	(62,368)
Employer Contributions	53,553	22,182	15,993	25,346	25,691	25,659
Plan Participants Contributions				1,963	1,644	2,185
Adjustment for Change in Measurement Date			14,490			7,904
Benefits Paid	(51,795)	(50,139)	(62,180)	(24,494)	(23,566)	(31,998)
Fair Value of Assets at End of Period	$ 601,719	$ 597,549	$ 563,881	$ 351,990	$ 353,269	$ 319,022
Net Amount Recognized at End of Period (Funded Status)	$ (348,058)	$ (326,944)	$ (267,615)	$ (133,462)	$ (119,138)	$ (148,273)
Amounts Recognized in the Balance Sheets Consist of:						
Non current Liabilities	$ (348,058)	$ (326,944)	$ (267,615)	$ (133,462)	$ (119,138)	$ (148,273)
Accumulated Benefit Obligation	$ 874,595	$ 843,526	$ 758,658	N/A	N/A	N/A

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Retirement Plan Year Ended September 30			Other Post-Retirement Benefits Year Ended September 30		
	2011	2010	2009	2011	2010	2009
			(Thousands)			
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	4.50%	4.75%	5.50%	4.50%	4.75%	5.50%
Rate of Compensation Increase	4.75%	4.75%	5.00%	4.75%	4.75%	5.00%
Components of Net Periodic Benefit Cost						
Service Cost	$ 14,772	$ 12,997	$ 10,913	$ 4,276	$ 4,298	$ 3,801
Interest Cost	42,676	44,308	46,836	21,884	25,017	27,499
Expected Return on Plan Assets	(59,103)	(58,342)	(57,958)	(29,165)	(26,334)	(31,615)
Amortization of Prior Service Cost	588	655	732	(1,710)	(1,710)	(1,074)
Amortization of Transition Amount				541	541	2,265
Recognition of Actuarial Loss(2)	34,873	21,641	5,676	23,794	25,881	9,271
Net Amortization and Deferral for Regulatory Purposes	(2,311)	(30)	12,817	10,490	351	18,037
Net Periodic Benefit Cost	$ 31,495	$ 21,229	$ 19,016	$ 30,110	$ 28,044	$ 28,184
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	4.75%	5.50%	6.75%	4.75%	5.50%	6.75%
Expected Return on Plan Assets	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Rate of Compensation Increase	4.75%	5.00%	5.00%	4.75%	5.00%	5.00%

(1) In fiscal 2011, the Company passed an amendment which changed the definition of annual compensation prospectively to exclude certain bonuses paid by Seneca after September 30, 2011. This decreased the benefit obligation of the Retirement Plan. In fiscal 2011, the Company also increased the prescription drug co-payments for certain retired participants which decreased the benefit obligation of the other post-retirement benefits. In fiscal 2009, the Company passed an amendment, affecting certain collectively bargained employees (mainly employees located in the state of Pennsylvania), which increased the participant drug co-payments and medical contributions for those active employees at the time of the amendment. This decreased the benefit obligation.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2011, the changes in such amounts during 2011, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2012 are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits (Thousands)	Non-Qualified Benefit Plans
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Loss	$ (428,735)	$ (182,228)	$ (35,574)
Transition Obligation		(18)	
Prior Service (Cost) Credit	(1,574)	13,356	
Net Amount Recognized	$ (430,309)	$ (168,890)	$ (35,574)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2011(1)			
Increase in Actuarial Gain/(Loss), excluding amortization(2)	$ (78,086)	$ (48,322)	$ (5,485)
Change due to Amortization of Actuarial (Gain)/Loss	34,873	23,794	3,860
Reduction in Transition Obligation		1,469	
Prior Service (Cost) Credit	2,351	4,549	
Net Change	$ (40,862)	$ (18,510)	$ (1,625)
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Loss	$ (39,614)	$ (24,057)	$ (4,363)
Transition Obligation		(10)	
Prior Service (Cost) Credit	(269)	2,138	
Net Amount Expected to be Recognized	$ (39,883)	$ (21,929)	$ (4,363)

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

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

In order to adjust the funded status of its pension (tax-qualified and non-qualified) and other post-retirement benefit plans at September 30, 2011, the Company recorded a $45.4 million increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $15.6 million (pre-tax) increase to Accumulated Other Comprehensive Loss.

The effect of the discount rate change for the Retirement Plan in 2011 was to increase the projected benefit obligation of the Retirement Plan by $26.9 million. In 2011, other actuarial experience (including the aforementioned amendment) decreased the projected benefit obligation for the Retirement Plan by $7.3 million. The effect of the discount rate change for the Retirement Plan in 2010 was to increase the projected benefit

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

obligation of the Retirement Plan by $75.1 million. The effect of the discount rate change for the Retirement Plan in 2009 was to increase the projected benefit obligation of the Retirement Plan by $102.6 million.

The Company made cash contributions totaling $53.6 million to the Retirement Plan during the year ended September 30, 2011. The Company expects that the annual contribution to the Retirement Plan in 2012 will be in the range of $40.0 million to $50.0 million. Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in 2012 in order to be in compliance with the Pension Protection Act of 2006.

The following Retirement Plan benefit payments, which reflect expected future service, are expected to be paid by the Retirement Plan during the next five years and the five years thereafter: $54.0 million in 2012; $54.8 million in 2013; $55.5 million in 2014; $56.5 million in 2015; $57.9 million in 2016; and $309.4 million in the five years thereafter.

In addition to the Retirement Plan discussed above, the Company also has Non-Qualified benefit plans that cover a group of management employees designated by the Chief Executive Officer of the Company. These plans provide for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit cost associated with these plans were $8.6 million, $7.4 million and $5.4 million in 2011, 2010 and 2009, respectively. The accumulated benefit obligations for the plans were $46.0 million, $41.8 million and $37.4 million at September 30, 2011, 2010 and 2009, respectively. The projected benefit obligations for the plans were $79.2 million, $73.9 million and $64.6 million at September 30, 2011, 2010 and 2009, respectively. The actuarial valuations for the plans were determined based on a discount rate of 3.75%, 4.25% and 5.25% as of September 30, 2011, 2010 and 2009, respectively and a weighted average rate of compensation increase of 8.0%, 8.0% and 8.25% as of September 30, 2011, 2010 and 2009, respectively.

The effect of the discount rate change in 2011 was to increase the other post-retirement benefit obligation by $14.5 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2011 by $6.6 million, primarily attributable to the impact of the change in prescription drug co-payments as noted above.

The effect of the discount rate change in 2010 was to increase the other post-retirement benefit obligation by $39.4 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2010 by $43.1 million, primarily attributable to updated pharmaceutical drug rebate experience as well as updated claim costs assumptions based on experience.

The effect of the discount rate change in 2009 was to increase the other post-retirement benefit obligation by $60.9 million. Effective October 1, 2009, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $27.0 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2009 by $32.1 million.

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 provides for a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. Since the Company is assumed to continue to provide a prescription drug benefit to retirees in the point of service and indemnity plans that is at least actuarially equivalent to Medicare Part D, the impact of the Act was reflected as of December 8, 2003.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Benefit Payments	Subsidy Receipts
2012	$ 25,465,000	$ (1,875,000)
2013	$ 26,703,000	$ (2,104,000)
2014	$ 27,986,000	$ (2,322,000)
2015	$ 29,333,000	$ (2,544,000)
2016	$ 30,697,000	$ (2,775,000)
2017 through 2021	$ 171,531,000	$ (17,193,000)

	2011	2010	2009
Rate of Increase for Pre Age 65 Participants	7.64%(1)	7.82%(1)	8.0%(1)
Rate of Increase for Post Age 65 Participants	6.89%(1)	6.95%(1)	7.0%(1)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	8.39%(1)	8.69%(1)	9.0%(1)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	6.89%(1)	6.95%(1)	7.0%(1)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	7.30%(1)	7.60%(1)	7.9%(1)

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

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2011 would increase by $56.5 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2011 by $3.7 million. If the health care cost trend rates were decreased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2011 would decrease by $47.5 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2011 by $3.1 million.

The Company made cash contributions totaling $25.2 million to its VEBA trusts and 401(h) accounts during the year ended September 30, 2011. In addition, the Company made direct payments of $0.2 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2011. The Company expects that the annual contribution to its VEBA trusts and 401(h) accounts in 2012 will be in the range of $15.0 million to $25.0 million.

Investment Valuation

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The inputs or methodology used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of September 30, 2011 and 2010, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall (based on the lowest level input that is significant to the fair value measurement in its entirety). (Dollars in Thousands):

	Total Fair Value Amounts at September 30, 2011	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(a)	$ 313,193	$ 215,524	$ 97,669	$
International Equities(b)	79,732	11,163	68,569	
Domestic Fixed Income(c)	146,587	77,657	68,930	
International Fixed Income(d)	43,153	887	42,266	
Hedge Fund Investments	39,296			39,296
Real Estate	6,443			6,443
Cash & Cash Equivalents	10,629		10,629	
Total Retirement Plan Investments	639,033	305,231	288,063	45,739
401(h) Investments	(37,176)	(17,744)	(16,773)	(2,659)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 601,857	$ 287,487	$ 271,290	$ 43,080
Accrued Income Receivable	467			
Accrued Administrative Costs	(605)			
Total Retirement Plan Assets	$ 601,719			

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

(b) International Equities include mostly collective trust funds and common stock.

(c) Domestic Fixed Income securities include mostly collective trust funds, corporate/government bonds and mortgages, and exchange traded funds.

(d) International Fixed Income securities includes mostly collective trust funds and exchange traded funds.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Total Fair Value Amounts at September 30, 2010	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(e)	$ 341,913	$ 172,841	$ 168,735	$ 337
International Equities(f)	99,587	21,051	78,536	
Domestic Fixed Income(g)	99,463	18,948	80,515	
International Fixed Income(h)	73,535		73,535	
Real Estate	6,148			6,148
Limited Partnerships	245			245
Cash & Cash Equivalents	11,146		11,146	
Total Retirement Plan Investments	632,037	212,840	412,467	6,730
401(h) Investments	(34,583)	(11,647)	(22,569)	(367)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 597,454	$ 201,193	$ 389,898	$ 6,363
Accrued Income Receivable	699			
Accrued Administrative Costs	(604)			
Total Retirement Plan Assets	$ 597,549			

(e) Domestic Equities include collective trust funds, common stock, convertible securities and preferred stock.

(f) International Equities include collective trust funds and common stock.

(g) Domestic Fixed Income securities include collective trust funds, corporate bonds, and exchange traded funds.

(h) International Fixed Income securities are comprised of collective trust funds.

	Total Fair Value Amounts at September 30, 2011	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				
Collective Trust Funds Domestic Equities	$ 148,451	$	$ 148,451	$
Collective Trust Funds International Equities	55,411		55,411	
Exchange Traded Funds Fixed Income	91,214	91,214		
Real Estate	1,561			1,561
Cash Held in Collective Trust Funds	12,890		12,890	

Total VEBA Trust Investments		309,527	91,214	216,752	1,561
401(h) Investments		37,176	17,744	16,773	2,659
Total Investments (including 401(h) Investments)	$	346,703	$ 108,958	$ 233,525	$ 4,220
Accrued Administrative Costs		(221)			
Claims Incurred But Not Reported		(1,854)			
Prepaid Federal Taxes		3,120			
Deferred Tax Asset		4,242			
Total Other Post-Retirement Benefit Assets	$	351,990			

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Total Fair Value Amounts at September 30, 2010	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				
Collective Trust Funds Domestic Equities	$ 217,637	$	$ 217,637	$
Collective Trust Funds International Equities	85,799		85,799	
Real Estate	3,824			3,824
Cash Held in Collective Trust Funds	7,622		7,622	
Total VEBA Trust Investments	314,882		311,058	3,824
401(h) Investments	34,583	11,647	22,569	367
Total Investments (including 401(h) Investments)	$ 349,465	$ 11,647	$ 333,627	$ 4,191
Accrued Income Receivable	640			
Accrued Administrative Costs	(196)			
Claims Incurred But Not Reported	(1,736)			
Prepaid Federal Taxes	2,866			
Deferred Tax Asset	2,230			
Total Other Post-Retirement Benefit Assets	$ 353,269			

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

The following tables provide a reconciliation of the beginning and ending balances of the Retirement Plan and other post-retirement benefit assets measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3). Note: For the years ended September 30, 2011 and 2010, there were no significant transfers in or out of Level 1 or Level 2. In addition, as shown in the following tables, there were no transfers in or out of Level 3.

Retirement Plan Level 3 Assets

Year Ended September 30, 2011
(Thousands of Dollars)

	Equity Convertible Securities (Domestic)	Hedge Funds	Limited Partnerships	Real Estate	Excluding 401(h) Investments	Total
Balance, Beginning of Year	$ 337	$	$ 245	$ 6,148	$ (367)	$ 6,363
Realized Gains/(Losses)	53		(4,846)	20	278	(4,495)
Unrealized Gains/(Losses)	(36)	(789)	4,853	159	(268)	3,919
Purchases, Sales, Issuances, and Settlements (Net)	(354)	40,085	(252)	116	(2,302)	37,293
Balance at September 30, 2011 (End of Year)	$	$ 39,296	$	$ 6,443	$ (2,659)	$ 43,080

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Retirement Plan Level 3 Assets

Year Ended September 30, 2010

(Thousands of Dollars)

	Equities		Fixed Income				
	Convertible Securities (Domestic)	Preferred Stock	Collateralized Mortgage Obligations (Part of Other)	Limited Partnerships	Real Estate	Excluding 401(h) Investments	Total
Balance, Beginning of Year	$ 770	$ 380	$ 569	$ 391	$ 7,894	$ (477)	$ 9,527
Realized Gains/(Losses)	53	(114)	1	(1,582)		90	(1,552)
Unrealized Gains/(Losses)	1		(21)	1,600	(2,427)	(24)	(871)
Purchases, Sales, Issuances, and Settlements (Net)	(487)	(266)	(549)	(164)	681	44	(741)
Balance at September 30, 2010 (End of Year)	$ 337	$	$	$ 245	$ 6,148	$ (367)	$ 6,363

Other Post-Retirement Benefit Level 3 Assets

Year Ended September 30, 2011
(Thousands of Dollars)

	VEBA Trust Investments		Other
	Real Estate	Including 401(h) Investments	Post-Retirement Benefit Investments
Balance, Beginning of Year	$ 3,824	$ 367	$ 4,191
Realized Gains/(Losses)		(278)	(278)
Unrealized Gains/(Losses)	(2,263)	268	(1,995)
Purchases, Sales, Issuances, and Settlements (Net)		2,302	2,302
Balance at September 30, 2011 (End of Year)	$ 1,561	$ 2,659	$ 4,220

Other Post-Retirement Benefit Level 3 Assets

Year Ended September 30, 2010
(Thousands of Dollars)

	VEBA Trust Investments		Other
	Real Estate	Including 401(h) Investments	Post-Retirement Benefit Investments
Balance, Beginning of Year	$ 3,816	$ 477	$ 4,293
Realized Gains/(Losses)		(90)	(90)

Unrealized Gains/(Losses)	8	24	32
Purchases, Sales, Issuances, and Settlements (Net)		(44)	(44)
Balance at September 30, 2010 (End of Year)	$ 3,824	$ 367	$ 4,191

The Company s assumption regarding the expected long-term rate of return on plan assets is 8.25%. The return assumption reflects the anticipated long-term rate of return on the plan s current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan s target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

The long-term investment objective of the Retirement Plan trust, the VEBA trusts and the 401(h) accounts is to achieve the target total return in accordance with the Company s risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). The target

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

allocation for the Retirement Plan is 55-70% equity securities, 25-40% fixed income securities and 5-20% other. The target allocation for the VEBA trusts (including 401(h) accounts) is 60-75% equity securities, 25-40% fixed income securities and 0-15% other. Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trusts, VEBA trusts and the 401(h) accounts have no significant concentrations of risk in any one country (other than the United States), industry or entity.

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

The discount rate which is used to present value the future benefit payment obligations of the Retirement Plan and the Company s other post-retirement benefits is 4.50% as of September 30, 2011. The discount rate which is used to present value the future benefit payment obligations of the Non-Qualified benefit plans is 3.75% as of September 30, 2011. The Company utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year s anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments.

Note I Commitments and Contingencies

Environmental Matters

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

It is the Company s policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2011, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $17.2 million to $21.4 million. The minimum estimated liability of $17.2 million has been recorded on the Consolidated Balance Sheet at September 30, 2011. The Company expects to recover its environmental clean-up costs through rate recovery. Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

(i) Former Manufactured Gas Plant Sites

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

The Company has agreed with the NYDEC to remediate another former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design work plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. An estimated minimum liability for remediation of this site of $14.4 million has been recorded.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(ii) Other

In June 2007, the NYDEC notified the Company, as well as a number of other companies, of their potential liability with respect to a remedial action at a waste disposal site in New York. The notification identified the Company as one of approximately 500 other companies considered to be PRPs related to this site and requested that the remedy the NYDEC proposed in a Record of Decision issued in March 2006 be performed. The estimated clean-up costs under the remedy selected by the NYDEC are estimated to be approximately $13.0 million if implemented. The Company participates in an organized group with other PRPs (the PRP Group) who are addressing this site. In April 2011, the Company entered into a Settlement Agreement and Liability Release with the PRP Group whereby the Company paid approximately $0.1 million in exchange for a general release of liability with respect to the waste disposal site.

In November 2010, the NYDEC notified the Company of its potential liability with respect to a remedial action at a former industrial site in New York. Along with the Company, notifications were sent to the City of Buffalo and the New York State Thruway Authority. Estimated clean-up costs associated with this site has not been completed and the Company cannot estimate its liability, if any, regarding remediation of this site at this time. In July 2011, the Company agreed to perform a limited scope of work at this site, which is pending.

Other

The Company, in its Utility segment, Energy Marketing segment, and All Other category, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. Substantially all of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $317.6 million in 2012, $89.6 million in 2013, $57.1 million in 2014, $50.8 million in 2015, $26.5 million in 2016 and $11.4 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment s service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of buildings, vehicles, construction tools, meters, computer equipment and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $5.7 million in 2012, $5.0 million in 2013, $4.5 million in 2014, $4.3 million in 2015, $4.2 million in 2016, and $11.3 million thereafter.

The Company, in its Pipeline and Storage segment and All Other category, has entered into several contractual commitments associated with various pipeline and gathering system expansion projects. As of September 30, 2011, the future contractual commitments related to the expansion projects are $83.1 million in 2012. There are no contractual commitments extending beyond 2012.

The Company, in its Exploration and Production segment, has entered into contractual obligations associated with well drilling, hydraulic fracturing and compression. The future contract commitments during the next three years are as follows: $93.9 million in 2012, $73.5 million in 2013 and $12.9 million in 2014.

The Company is involved in other litigation arising in the normal course of business. In addition to the regulatory matters discussed in Note C Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business. These other litigation and regulatory matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

Note J Discontinued Operations

On September 1, 2010, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. Those operations consisted of short distance landfill gas pipeline companies engaged in the purchase, sale and transportation of landfill gas. The Company s landfill gas operations were maintained under the Company s wholly-owned subsidiary, Horizon LFG. The Company received approximately $38.0 million of proceeds from the sale. The sale resulted in the recognition of a gain of approximately $6.3 million, net of tax, during the fourth quarter of 2010. The decision to sell was based on progressing the Company s strategy of divesting its smaller, non-core assets in order to focus on its core businesses, including the development of the Marcellus Shale and the construction of key pipeline infrastructure projects throughout the Appalachian region. As a result of the decision to sell the landfill gas operations, the Company began presenting these operations as discontinued operations during the fourth quarter of 2010.

The following is selected financial information of the discontinued operations for the sale of the Company s landfill gas operations:

	Year Ended September 30	
	2010	2009
	(Thousands)	
Operating Revenues	$ 9,919	$ 6,309
Operating Expenses	8,933	10,705
Operating Income (Loss)	986	(4,396)
Other Income	4	8
Interest Income	2	
Interest Expense	29	127
Income (Loss) before Income Taxes	963	(4,515)
Income Tax Expense (Benefit)	493	(1,739)
Income (Loss) from Discontinued Operations	470	(2,776)
Gain on Disposal, Net of Taxes of $4,024	6,310	
Income (Loss) from Discontinued Operations	$ 6,780	$ (2,776)

Note K Business Segment Information

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

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

The Pipeline and Storage segment operations are regulated by the FERC for both Supply Corporation and Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers (including NFR), exploration and production companies (including Seneca) and pipeline companies in the northeastern United States markets. Empire transports natural gas

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

from the United States/Canadian border near Buffalo, New York into Central New York just north of Syracuse, New York. Empire s new facilities (the Empire Connector), which consists of a compressor station and a pipeline extension from near Rochester, New York to an interconnection near Corning, New York with the unaffiliated Millennium Pipeline, were placed into service on December 10, 2008. Empire transports gas to major industrial companies, utilities (including Distribution Corporation) and power producers.

The Exploration and Production segment, through Seneca, is engaged in exploration for, and development and purchase of, natural gas and oil reserves in California and in the Appalachian region of the United States. The Company completed the sale of its off-shore oil and natural gas properties in April 2011 as a result of the segment s increasing emphasis on the Marcellus Shale play within the Appalachian region. Seneca s production is, for the most part, sold to purchasers located in the vicinity of its wells. In November 2010, the Company acquired oil and gas properties in the Covington Township area of Tioga County, Pennsylvania from EOG Resources, Inc. for approximately $24.1 million. In addition, the Company acquired two tracts of leasehold acreage in March 2010 for approximately $71.8 million. These tracts, consisting of approximately 18,000 net acres in Tioga and Potter Counties in Pennsylvania, are geographically similar to the Company s existing Marcellus Shale acreage in the area. On July 20, 2009, Seneca acquired Ivanhoe Energy s United States oil and gas operations for approximately $34.9 million, net of cash acquired. Ivanhoe Energy s United States oil and gas operations were incorporated into the Company s consolidated financial statements for the period subsequent to the completion of the acquisition on July 20, 2009.

The Energy Marketing segment is comprised of NFR s operations. NFR markets natural gas to industrial, wholesale, commercial, public authority and residential customers primarily in western and central New York and northwestern Pennsylvania, offering competitively priced natural gas for its customers.

The data presented in the tables below reflect financial information for the segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. The Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income.

	Year Ended September 30, 2011							
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	$ 835,853	$ 134,071	$ 519,035	$ 284,546	$ 1,773,505	$ 4,401	$ 936	$ 1,778,842
Intersegment Revenues	$ 16,642	$ 81,037	$	$ 420	$ 98,099	$ 10,017	$ (108,116)	$
Interest Income	$ 2,049	$ 324	$ (27)	$ 104	$ 2,450	$ 247	$ 219	$ 2,916
Interest Expense	$ 34,440	$ 25,737	$ 17,402	$ 20	$ 77,599	$ 2,173	$ (1,651)	$ 78,121
Depreciation, Depletion and Amortization	$ 40,808	$ 37,266	$ 146,806	$ 47	$ 224,927	$ 840	$ 760	$ 226,527
Income Tax Expense (Benefit)	$ 33,325	$ 19,854	$ 89,034	$ 4,489	$ 146,702	$ 18,961	$ (1,282)	$ 164,381
Income (Loss) from Unconsolidated Subsidiaries	$	$	$	$	$	$ (759)	$	$ (759)
Gain on Sale of Unconsolidated Subsidiaries	$	$	$	$	$	$ 50,879(5)	$	$ 50,879
Segment Profit: Net Income (Loss)	$ 63,228	$ 31,515	$ 124,189	$ 8,801	$ 227,733	$ 38,502	$ (7,833)	$ 258,402
Expenditures for Additions to Long-Lived Assets	$ 58,398	$ 129,206	$ 648,815	$ 460	$ 836,879	$ 17,022	$ 285	$ 854,186

At September 30, 2011

					(Thousands)			
Segment Assets	$ 2,046,017	$ 1,131,681	$ 1,885,014	$ 71,138	$ 5,133,850	$ 166,730	$ (15,838)	$ 5,284,742

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Year Ended September 30, 2010							
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	$ 804,466	$ 138,905	$ 438,028	$ 344,802	$ 1,726,201	$ 33,428	$ 874	$ 1,760,503
Intersegment Revenues	$ 15,324	$ 79,978	$	$	$ 95,302	$ 2,315	$ (97,617)	$
Interest Income	$ 2,144	$ 199	$ 980	$ 44	$ 3,367	$ 137	$ 225	$ 3,729
Interest Expense	$ 35,831	$ 26,328	$ 30,853	$ 27	$ 93,039	$ 2,152	$ (1,245)	$ 93,946
Depreciation, Depletion and Amortization	$ 40,370	$ 35,930	$ 106,182	$ 42	$ 182,524	$ 7,907	$ 768	$ 191,199
Income Tax Expense (Benefit)	$ 31,858	$ 22,634	$ 78,875	$ 4,806	$ 138,173	$ 464	$ (1,410)	$ 137,227
Income from Unconsolidated Subsidiaries	$	$	$	$	$	$ 2,488	$	$ 2,488
Segment Profit: Income (Loss) from Continuing Operations	$ 62,473	$ 36,703	$ 112,531	$ 8,816	$ 220,523	$ 3,396	$ (4,786)	$ 219,133
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 57,973	$ 37,894	$ 398,174	$ 407	$ 494,448	$ 6,694	$ 210	$ 501,352
	At September 30, 2010 (Thousands)							
Segment Assets	$ 2,071,530	$ 1,094,914	$ 1,539,705	$ 69,561	$ 4,775,710	$ 198,706	$ 131,209	$ 5,105,625

	Year Ended September 30, 2009							
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	$ 1,097,550	$ 137,478	$ 382,758	$ 397,763	$ 2,015,549	$ 35,100	$ 894	$ 2,051,543
Intersegment Revenues	$ 15,474	$ 81,795	$	$ 558	$ 97,827	$	$ (97,827)	$
Interest Income	$ 2,486	$ 995	$ 2,430	$ 79	$ 5,990	$ 583	$ (797)	$ 5,776
Interest Expense	$ 32,417	$ 21,580	$ 33,368	$ 215	$ 87,580	$ 2,344	$ (3,135)	$ 86,789
Depreciation, Depletion and Amortization	$ 39,675	$ 35,115	$ 90,816	$ 42	$ 165,648	$ 4,276	$ 696	$ 170,620
Income Tax Expense (Benefit)	$ 37,097	$ 30,579	$ (14,616)	$ 4,470	$ 57,530	$ (3,482)	$ (1,189)	$ 52,859
Income from Unconsolidated Subsidiaries	$	$	$	$	$	$ 3,366	$	$ 3,366
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	$	$	$ 182,811	$	$ 182,811	$	$	$ 182,811
Significant Non-Cash Item: Impairment of Investment in Partnership	$	$	$	$	$	$ 1,804(2)	$	$ 1,804
Segment Profit: Income (Loss) from Continuing Operations	$ 58,664	$ 47,358	$ (10,238)	$ 7,166	$ 102,950	$ 705	$ (171)	$ 103,484
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 56,178	$ 52,504	$ 223,223(3)	$ 25	$ 331,930	$ 9,507	$ (47)	$ 341,390
	At September 30, 2009 (Thousands)							
Segment Assets	$ 2,132,610	$ 1,046,372	$ 1,265,678	$ 52,469	$ 4,497,129	$ 210,809(4)	$ 61,191	$ 4,769,129

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

(2) Amount represents the impairment in the value of the Company s 50% investment in ESNE, a partnership that owns an 80-megawatt, combined cycle, natural gas-fired power plant in the town of North East, Pennsylvania.

(3) Amount includes the acquisition of Ivanhoe Energy s United States oil and gas operation for $34.9 million, net of cash acquired.

(4) Amount includes $28,761 of assets of the Company s landfill gas operations, which have been classified as discontinued operations as of September 30, 2010. (See Note J Discontinued Operations).

(5) In February 2011, the Company sold its 50% equity method investments in Seneca Energy and Model City for $59.4 million, resulting in a gain of $50.9 million.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Geographic Information	2011	At September 30 2010 (Thousands)	2009
Long-Lived Assets:			
United States	$ 4,899,430	$ 4,330,248	$ 3,963,398
Assets of Discontinued Operations			28,761
	$ 4,899,430	$ 4,330,248	$ 3,992,159

Note L Investments in Unconsolidated Subsidiaries

At September 30, 2011, the Company owns a 50% interest in ESNE. ESNE is an 80-megawatt, combined cycle, natural gas-fired turbine power plant in North East, Pennsylvania that is in the process of being dismantled. The Company expects to recover its investment in ESNE through the sale of ESNE s major assets, such as the power turbines.

In February 2011, the Company sold its 50% equity method investments in Seneca Energy and Model City for $59.4 million, resulting in a gain of $50.9 million. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties.

A summary of the Company s investments in unconsolidated subsidiaries at September 30, 2011 and 2010 is as follows:

	At September 30 2011	2010 (Thousands)
Seneca Energy	$	$ 11,007
Model City		2,017
ESNE	1,306	1,804
	$ 1,306	$ 14,828

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note M Quarterly Financial Data (unaudited)

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

Quarter Ended	Operating Revenues	Operating Income	Income from Continuing Operations	Income (Loss) from Discontinued Operations	Net Income Available for Common Stock	Earnings from Continuing Operations per Common Share Basic	Earnings from Continuing Operations per Common Share Diluted	Earnings per Common Share Basic	Earnings per Common Share Diluted
	(Thousands, except per common share amounts)								
2011									
9/30/2011	$ 286,034	$ 75,191	$ 37,356	$	$ 37,356	$ 0.45	$ 0.45	$ 0.45	$ 0.45
6/30/2011	$ 380,979	$ 94,805	$ 46,891	$	$ 46,891	$ 0.57	$ 0.56	$ 0.57	$ 0.56
3/31/2011	$ 660,881	$ 153,756	$ 115,611	$	$ 115,611(1)	$ 1.40	$ 1.38	$ 1.40	$ 1.38
12/31/2010	$ 450,948	$ 117,410	$ 58,544	$	$ 58,544	$ 0.71	$ 0.70	$ 0.71	$ 0.70
2010									
9/30/2010	$ 286,396	$ 73,995	$ 32,393	$ 6,009(2)	$ 38,402(2)	$ 0.40	$ 0.39	$ 0.47	$ 0.46
6/30/2010	$ 351,992	$ 89,188	$ 42,641	$ (57)	$ 42,584	$ 0.52	$ 0.51	$ 0.52	$ 0.51
3/31/2010	$ 667,980	$ 151,631	$ 79,874	$ 554	$ 80,428	$ 0.98	$ 0.96	$ 0.99	$ 0.97
12/31/2009	$ 454,135	$ 125,637	$ 64,225	$ 274	$ 64,499	$ 0.80	$ 0.78	$ 0.80	$ 0.78

(1) Includes a $31.4 million after tax gain on the sale of the Company s 50% equity method investments in Seneca Energy and Model City.

(2) Includes a $6.3 million gain on the sale of the Company s landfill gas operations.

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

At September 30, 2011, there were 14,355 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange. Information related to restrictions on the payment of dividends can be found in Note E Capitalization and Short-Term Borrowings. The quarterly price ranges (based on intra-day prices) and quarterly dividends declared for the fiscal years ended September 30, 2011 and 2010, are shown below:

Quarter Ended	Price Range High	Price Range Low	Dividends Declared
2011			
9/30/2011	$ 75.98	$ 48.67	$ .355
6/30/2011	$ 75.75	$ 66.39	$ .355
3/31/2011	$ 74.00	$ 65.80	$ .345

12/31/2010	$ 66.52	$ 51.66	$	.345
2010				
9/30/2010	$ 52.29	$ 42.83	$	.345
6/30/2010	$ 54.42	$ 44.27	$	.345
3/31/2010	$ 52.48	$ 45.64	$	.335
12/31/2009	$ 52.00	$ 43.62	$	.335

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note O Supplementary Information for Oil and Gas Producing Activities (unaudited)

As of September 30, 2010, the Company adopted the revisions to authoritative guidance related to oil and gas exploration and production activities that aligned the reserve estimation and disclosure requirements with the requirements of the SEC Modernization of Oil and Gas Reporting rule, which the Company also adopted. The new SEC rules require companies to value their year-end reserves using an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve month period prior to the end of the reporting period.

The following supplementary information is presented in accordance with the authoritative guidance regarding disclosures about oil and gas producing activities and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars. As discussed in Note A, the Company completed the sale of its off-shore oil and natural gas properties in the Gulf of Mexico in April 2011. With the completion of this sale, the Company no longer has any off-shore oil and gas properties.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30	
	2011	2010
	(Thousands)	
Proved Properties(1)	$ 2,010,662	$ 2,267,009
Unproved Properties	226,276	151,232
	2,236,938	2,418,241
Less Accumulated Depreciation, Depletion and Amortization	499,671	1,094,377
	$ 1,737,267	$ 1,323,864

(1) Includes asset retirement costs of $32.7 million and $69.8 million at September 30, 2011 and 2010, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Following is a summary of costs excluded from amortization at September 30, 2011:

	Total as of September 30, 2011	Year Costs Incurred			
		2011	2010	2009	Prior
			(Thousands)		
Acquisition Costs	$ 104,163	$	$ 69,206	$ 34,957	$
Development Costs	112,530	111,485	1,045		
Exploration Costs	7,911	894	7,017		

Capitalized Interest	1,672	1,516	156		
	$ 226,276	$ 113,895	$ 77,424	$ 34,957	$

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ 28,838	$ 790	$ 35,803
Unproved	20,012	80,221	44,528
Exploration Costs	62,651(1)	75,155(1)	11,724
Development Costs	519,285(2)	234,094(2)	125,109
Asset Retirement Costs	12,087	3,901	2,877
	$ 642,873	$ 394,161	$ 220,041

(1) Amounts for 2011 and 2010 include capitalized interest of $0.8 million and $0.2 million, respectively

(2) Amounts for 2011 and 2010 include capitalized interest of $0.7 million and $0.9 million, respectively.

For the years ended September 30, 2011, 2010 and 2009, the Company spent $199.2 million, $28.9 million and $24.2 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2011	2010	2009
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $23, $253 and $239, respectively)	$ 223,648	$ 152,163	$ 106,815
Oil, Condensate and Other Liquids	273,952	233,569	174,356
Total Operating Revenues(1)	497,600	385,732	281,171
Production/Lifting Costs	73,250	61,398	53,957
Franchise/Ad Valorem Taxes	12,179	10,592	8,657
Accretion Expense	3,668	5,444	5,437
Depreciation, Depletion and Amortization ($2.12, $2.10 and $2.10 per Mcfe of production)	143,372	104,092	89,307
Impairment of Oil and Gas Producing Properties(2)			182,811
Income Tax Expense (Benefit)	110,117	83,946	(27,055)
	$ 155,014	$ 120,260	$ (31,943)

Results of Operations for Producing Activities (excluding corporate overheads and interest charges)

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

(2) See discussion of impairment in Note A Summary of Significant Accounting Policies.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Reserve Quantity Information

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

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

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The reliable technologies that were utilized in estimating the reserves include wire line open-hole 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.

	Gas MMcf			
	Appalachian Region	U. S. West Coast Region	Gulf Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
September 30, 2008	128,398	72,860	24,641	225,899
Extensions and Discoveries	49,249	3,282	6,698	59,229
Revisions of Previous Estimates	(19,484)	488	9,407	(9,589)(1)
Production	(8,335)	(4,063)	(9,886)	(22,284)
Purchases of Minerals in Place		392		392
Sales of Minerals in Place			(4,693)	(4,693)
September 30, 2009	149,828	72,959	26,167	248,954
Extensions and Discoveries	189,979(2)	269	2,881	193,129
Revisions of Previous Estimates	7,677	2,315	6,683	16,675
Production	(16,222)(3)	(3,819)	(10,304)	(30,345)
September 30, 2010	331,262	71,724	25,427	428,413
Extensions and Discoveries	249,047(2)	195	158	249,400
Revisions of Previous Estimates	24,486	526	1,373	26,385
Production	(42,979)(3)	(3,447)	(4,041)	(50,467)
Purchases of Minerals in Place	44,790			44,790
Sales of Minerals in Place		(682)	(22,917)	(23,599)
September 30, 2011	606,606	68,316		674,922
Proved Developed Reserves:				
September 30, 2008	115,824	68,453	18,242	202,519
September 30, 2009	120,579	67,603	18,051	206,233
September 30, 2010	210,817	66,178	19,293	296,288
September 30, 2011	350,458	63,965		414,423
Proved Undeveloped Reserves:				
September 30, 2008	12,574	4,407	6,399	23,380
September 30, 2009	29,249	5,356	8,116	42,721
September 30, 2010	120,445	5,546	6,134	132,125
September 30, 2011	256,148	4,351		260,499

(1)

During 2009, the Company made a downward revision of its proved developed and undeveloped reserves amounting to 9,589 MMcf. This was primarily attributable to a 19,484 MMcf reduction in the Appalachian region offset by a 9,407 MMcf increase in the Gulf Coast region. The reduction in the Appalachian region was mainly due to declining natural gas prices, which made certain reserves uneconomical. The improvement in the Gulf Coast region was due to improved performance of Gulf Coast properties.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(2) Extensions and discoveries include 182 Bcf (during 2010) and 249 Bcf (during 2011) of Marcellus Shale gas in the Appalachian Region.

(3) Production includes 7,180 MMcf (during 2010) and 35,356 MMcf (during 2011) from Marcellus Shale fields (which exceed 15% of total reserves).

	Oil Mbbl			
		U. S.		
	Appalachian Region	West Coast Region	Gulf Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
September 30, 2008	396	44,444	1,358	46,198
Extensions and Discoveries	15	896	302	1,213
Revisions of Previous Estimates	(41)	43	447	449
Production	(59)	(2,674)(1)	(640)	(3,373)
Purchases of Minerals in Place		2,115		2,115
Sales of Minerals in Place			(15)	(15)
September 30, 2009	311	44,824	1,452	46,587
Extensions and Discoveries	4	828	222	1,054
Revisions of Previous Estimates	2	484	332	818
Production	(49)	(2,669)(1)	(502)	(3,220)
September 30, 2010	268	43,467	1,504	45,239
Extensions and Discoveries	10	756	1	767
Revisions of Previous Estimates	46	1,909	(339)	1,616
Production	(45)	(2,628)	(187)	(2,860)
Sales of Minerals in Place		(438)	(979)	(1,417)
September 30, 2011	279	43,066		43,345
Proved Developed Reserves:				
September 30, 2008	357	37,224	1,313	38,894
September 30, 2009	285	37,711	1,194	39,190
September 30, 2010	263	36,353	1,066	37,682
September 30, 2011	274	37,306		37,580
Proved Undeveloped Reserves:				
September 30, 2008	39	7,220	45	7,304
September 30, 2009	26	7,113	258	7,397
September 30, 2010	5	7,114	438	7,557
September 30, 2011	5	5,760		5,765

(1) The Midway Sunset North fields (which exceeded 15% of total reserves at September 30, 2010) contributed 1,680 Mbbls and 1,543 Mbbls of production during 2009 and 2010, respectively. As of September 30, 2011, the Midway Sunset North fields were below 15% of total

reserves.

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.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company s PUD reserves increased from 87 Bcfe at September 30, 2009 to 177 Bcfe at September 30, 2010. Undeveloped 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 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 PUD locations in this field is scheduled over the next three years as steam generation capacity is increased and the steam-flood here matures.

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

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company s oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, as a result of the SEC s final rule on Modernization of Oil and Gas Reporting (effective fiscal 2010), it is based on the unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period and costs

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

adjusted only for existing contractual changes. It assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

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

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
United States			
Future Cash Inflows	$ 7,180,320	$ 5,273,605	$ 3,972,026
Less:			
Future Production Costs	1,555,603	1,347,855	1,010,851
Future Development Costs	636,745	445,413	312,717
Future Income Tax Expense at Applicable Statutory Rate	1,834,778	1,186,567	916,466
Future Net Cash Flows	3,153,194	2,293,770	1,731,992
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,629,037	1,120,182	856,015
Standardized Measure of Discounted Future Net Cash Flows	$ 1,524,157	$ 1,173,588	$ 875,977

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

	Year Ended September 30		
	2011	2010	2009
		(Thousands)	
United States			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	$ 1,173,588	$ 875,977	$ 1,267,844
Sales, Net of Production Costs	(412,172)	(313,742)	(218,557)
Net Changes in Prices, Net of Production Costs	404,445	176,530	(699,217)
Purchases of Minerals in Place	52,697		38,902
Sales of Minerals in Place	(73,633)		(20,141)
Extensions and Discoveries	218,140	329,555	66,002
Changes in Estimated Future Development Costs	(85,191)	(17,353)	(22,392)
Previously Estimated Development Costs Incurred	168,275	47,539	53,285
Net Change in Income Taxes at Applicable Statutory Rate	(249,773)	(85,703)	331,251
Revisions of Previous Quantity Estimates	124,545	46,246	(27,864)
Accretion of Discount and Other	203,236	114,539	106,864
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$ 1,524,157	$ 1,173,588	$ 875,977

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Schedule II Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts(1)	Deductions(2)	Balance at End of Period
Year Ended September 30, 2011					
Allowance for Uncollectible Accounts	$ 30,961	$ 11,974	$ 2,484	$ 14,380	$ 31,039
Year Ended September 30, 2010					
Allowance for Uncollectible Accounts	$ 38,334	$ 15,422	$ 2,268	$ 25,063	$ 30,961
Year Ended September 30, 2009					
Allowance for Uncollectible Accounts	$ 33,117	$ 31,464	$ 2,751	$ 28,998	$ 38,334

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

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

Item 9 ***Changes in and Disagreements with Accountants on Accounting and Financial Disclosure***
None

Item 9A ***Controls and Procedures***
Evaluation of Disclosure Controls and Procedures

The term disclosure controls and procedures is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company s management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company s management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company s disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company s Chief Executive Officer and Principal Financial Officer concluded that the Company s disclosure controls and procedures were effective as of September 30, 2011.

Management s Annual Report on Internal Control over Financial Reporting

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

The Company s management assessed the effectiveness of the Company s internal control over financial reporting as of September 30, 2011. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2011.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company s consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company s internal control over financial reporting as of September 30, 2011. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in the Company s internal control over financial reporting that occurred during the quarter ended September 30, 2011 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Item 9B ***Other Information***

None

PART III

Item 10 ***Directors, Executive Officers and Corporate Governance***

The information required by this item concerning the directors of the Company and corporate governance is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2012 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2011. The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled Nominees for Election as Directors for Three-Year Terms to Expire in 2015, Directors Whose Terms Expire in 2014, Directors Whose Terms Expire in 2013, and Section 16(a) Beneficial Ownership Reporting Compliance and is incorporated herein by reference. The information concerning corporate governance will be set forth in the definitive Proxy Statement under the heading entitled Meetings of the Board of Directors and Standing Committees and is incorporated herein by reference. Information concerning the Company s executive officers can be found in Part I, Item 1, of this report.

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

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

Item 11 ***Executive Compensation***

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2012 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2011. The information concerning executive compensation will be set forth in the definitive Proxy Statement under the headings Executive Compensation and Compensation Committee Interlocks and Insider Participation and, excepting the Report of the Compensation Committee, is incorporated herein by reference.

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Item 12 ***Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***
Equity Compensation Plan Information

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2012 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2011. The equity compensation plan information will be set forth in the definitive Proxy Statement under the heading Equity Compensation Plan Information and is incorporated herein by reference.

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2012 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2011. The information concerning security ownership of certain beneficial owners will be set forth in the definitive Proxy Statement under the heading Security Ownership of Certain Beneficial Owners and Management and is incorporated herein by reference.

(b) Security Ownership of Management

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2012 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2011. The information concerning security ownership of management will be set forth in the definitive Proxy Statement under the heading Security Ownership of Certain Beneficial Owners and Management and is incorporated herein by reference.

(c) Changes in Control

None

Item 13 ***Certain Relationships and Related Transactions, and Director Independence***
The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2012 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2011. The information regarding certain relationships and related transactions will be set forth in the definitive Proxy Statement under the headings Compensation Committee Interlocks and Insider Participation and Related Person Transactions and is incorporated herein by reference. The information regarding director independence is set forth in the definitive Proxy Statement under the heading Director Independence and is incorporated herein by reference.

Item 14 ***Principal Accountant Fees and Services***
The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2012 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2011. The information concerning principal accountant fees and services will be set forth in the definitive Proxy Statement under the heading Audit Fees and is incorporated herein by reference.

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PART IV

Item 15 ***Exhibits and Financial Statement Schedules***

(a)1. Financial Statements
Financial statements filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)2. Financial Statement Schedules
Financial statement schedules filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)3. Exhibits

Exhibit Number	Description of Exhibits
3(i)	Articles of Incorporation:
	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
	Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 3(ii), Form 8-K dated March 14, 2005 in File No. 1-3880)
3(ii)	By-Laws:
	National Fuel Gas Company By-Laws as amended March 10, 2011 (Exhibit 3.1, Form 8-K dated March 14, 2011 in File No. 1-3880)
4	Instruments Defining the Rights of Security Holders, Including Indentures:
	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
	Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992 in File No. 1-3880)
	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992 in File No. 1-3880)
	Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
	Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993 in File No. 1-3880)

Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)

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Exhibit Number	Description of Exhibits
	Officers Certificate Establishing Medium-Term Notes, dated October 14, 1999 (Exhibit 4.2, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
	Officers Certificate establishing 5.25% Notes due 2013, dated February 18, 2003 (Exhibit 4, Form 10-Q for the quarterly period ended March 31, 2003 in File No. 1-3880)
	Officer s Certificate establishing 6.50% Notes due 2018, dated April 11, 2008 (Exhibit 4.1, Form 10-Q for the quarterly period ended June 30, 2008 in File No. 1-3880)
	Officer s Certificate establishing 8.75% Notes due 2019, dated April 6, 2009 (Exhibit 4.4, Form 8-K dated April 6, 2009 in File No. 1-3880)
	Amended and Restated Rights Agreement, dated as of December 4, 2008, between the Company and The Bank of New York Mellon (formerly The Bank of New York), as rights agent (Exhibit 4.1, Form 8-K dated December 4, 2008 in File No. 1-3880)
10	Material Contracts:
	Credit Agreement, dated as of August 18, 2010, among the Company, the Lenders Party Thereto, JPMorgan Chase Bank, National Association, as Administrative Agent, and PNC Bank, National Association, as Syndication Agent (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2010 in File No. 1-3880)
	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006 in File No. 1-3880)
	Resolutions adopted by the National Fuel Gas Company Board of Directors on February 21, 2008 regarding director stock ownership guidelines (Exhibit 10.5, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880)
	Management Contracts and Compensatory Plans and Arrangements:
	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of David P. Bauer, Karen M. Camiolo, Carl M. Carlotti, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, Seneca Resources Corporation and Matthew D. Cabell (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
	Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
	Description of September 17, 2009 restricted stock award (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2009 in File No. 1-3880)
	Description of post-employment medical and prescription drug benefits (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2009 in File No. 1-3880)
	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880)
	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005 in File No. 1-3880)
	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006 in File No. 1-3880)

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Exhibit Number	Description of Exhibits
	Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
	Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880)
	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2008 in File No. 1-3880)
	Form of Restricted Stock Award Notice under the National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2010 in File No. 1-3880)
	Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
	National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 8-K dated March 17, 2010 in File No. 1-3880)
	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2010 in File No. 1-3880)
	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2010 in File No. 1-3880)
	Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
	Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2009 in File No. 1-3880)
	Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2010 in File No. 1-3880)
	National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009 in File No. 1-3880)
	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective December 8, 2010 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2010 in File No. 1-3880)
	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994 in File No. 1-3880)

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Exhibit Number	Description of Exhibits
	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880)
	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880)
	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
	Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
	National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997 in File No. 1-3880)
	Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
	Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
	Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
	National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005 in File No. 1-3880)
	National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880)
	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)

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Exhibit Number	Description of Exhibits
	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
	Life Insurance Premium Agreement, dated September 17, 2009, between the Company and David F. Smith (Exhibit 10.1, Form 8-K dated September 23, 2009 in File No. 1-3880)
	National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001, in File No. 1-3880)
	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007 (Exhibit 10.4, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880)
	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008 in File No. 1-3880)
	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010 in File No. 1-3880)
	National Fuel Gas Company and Participating Subsidiaries 1996 Executive Retirement Plan Trust Agreement (II), dated May 10, 1996 (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
	National Fuel Gas Company Participating Subsidiaries Executive Retirement Plan 2003 Trust Agreement(I), dated September 1, 2003 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
	National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 8-K dated June 3, 2005 in File No. 1-3880)
	Description of long-term performance incentives for the period October 1, 2008 to September 30, 2011 under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2008 in File No. 1-3880)

Exhibit Number	Description of Exhibits
	Description of long-term performance incentives for the period October 1, 2009 to September 30, 2012 under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2009 in File No. 1-3880)
	Description of long-term performance incentives for the period October 1, 2010 to September 30, 2013 under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2010 in File No. 1-3880)
	Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of March 20, 1997 regarding the Retainer Policy for Non-Employee Directors (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
	National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2009 in File No. 1-3880)
	Amended and Restated Retirement Benefit Agreement for David F. Smith, dated September 20, 2007, among the Company, National Fuel Gas Supply Corporation and David F. Smith (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880)
	Description of assignment of interests in certain life insurance policies (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
	Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880)
	Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006 in File No. 1-3880)
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2007 through 2011
21	Subsidiaries of the Registrant
23	Consents of Experts:
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation