NATIONAL FUEL GAS CO
Form 10-K
November 24, 2010

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, 2010

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

For the Transition Period from to

Commission File Number 1-3880

National Fuel Gas Company
(Exact name of registrant as specified in its charter)

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

(716) 857-7000

Registrant s telephone number, including area code

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

Title of Each Class	**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 o

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 o 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 o

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 o

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. þ

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer þ	Accelerated filer o	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $4,041,725,000 as of March 31, 2010.

Common Stock, $1 Par Value, outstanding as of October 31, 2010: 82,190,871 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive Proxy Statement for its 2011 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

Glossary of Terms

Frequently used abbreviations, acronyms, or terms used in this report:

National Fuel Gas Companies

Company The Registrant, the Registrant and its subsidiaries or the Registrant s subsidiaries as appropriate in the context of the disclosure

Distribution Corporation National Fuel Gas Distribution Corporation

Empire Empire Pipeline, Inc.

ESNE Energy Systems North East, LLC

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

Toro Toro Partners, LP

Regulatory Agencies

EPA United States Environmental Protection Agency

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

NYDEC New York State Department of Environmental Conservation

NYPSC State of New York Public Service Commission

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.

Board foot A measure of lumber and/or timber equal to 12 inches in length by 12 inches in width by one inch in thickness.

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.

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.

Grid The layout of the electrical transmission system or a synchronized transmission network.

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 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
Spot gas purchases The purchase of natural gas on a short-term basis.
Stock acquisitions Investments in corporations.
Unbundled service A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
VEBA Voluntary Employees Beneficiary Association

WNC Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

For the Fiscal Year Ended September 30, 2010

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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, 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, proje 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 728,700 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, in the Appalachian region of the United States, and in the shallow waters of the Gulf Coast region of Texas and Louisiana, including offshore areas in federal waters and some state waters. At September 30, 2010, the Company had U.S. proved developed and undeveloped reserves of 45,239 Mbbl of oil and 428,413 MMcf of natural gas.

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 are not included in any of the four reported business segments and include the following active companies:

Highland Forest Resources, Inc. (Highland), a New York corporation which, together with a division of Seneca known as its Northeast Division, markets timber from Appalachian land holdings. At September 30, 2010, the Company owned approximately 100,000 acres of timber property and managed an additional 3,424 acres of timber cutting rights;

Horizon Energy Development, Inc. (Horizon), a New York corporation formed to engage in foreign and domestic energy projects through investments as a sole or substantial owner in various business entities. These entities include Horizon s wholly owned subsidiary, Horizon Energy Holdings, Inc., a New York corporation, which owns 100% of Horizon Energy Development B.V. (Horizon B.V.). Horizon B.V. is a Dutch company that is in the process of winding up or selling certain power development projects in Europe;

Horizon Power, Inc. (Horizon Power), a New York corporation which is an exempt wholesale generator under PUHCA 2005 and is operating landfill gas electric generation facilities; 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 2010.

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 28.5% of the Company s 2010 income from continuing operations and 27.7% of the Company s 2010 net income available for common stock.

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 16.7% of the Company s 2010 income from continuing operations and 16.2% of the Company s 2010 net income available for common stock.

Supply Corporation has service agreements for all of its firm storage capacity, totaling 68,408 MDth. The Utility segment has contracted for 27,865 MDth or 40.7% of the total firm storage capacity, and the Energy Marketing segment accounts for another 4,811 MDth or 7.1% of the total firm storage capacity. Nonaffiliated customers have contracted for the remaining 35,732 MDth or 52.2% 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 2011, 88.1% of Supply Corporation s total firm storage capacity was committed under contracts that, subject to 2010 shipper or Supply Corporation notifications, could have been terminated effective in 2011. Supply Corporation received storage contract termination notifications in 2010 totaling approximately 5,300 MDth of storage capacity. Supply Corporation expects to remarket this capacity with service beginning April 1, 2011.

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 2,134 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,065 MDth per day or 49.9% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 126 MDth per day or 5.9% of contracted transportation capacity. The remaining 943 MDth or 44.2% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2011, 53.8% of Supply Corporation s contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2011 or, subject to 2010 shipper or Supply Corporation notifications, could have been terminated effective in 2011. Based on contract expirations and termination notices received in 2010 for 2011 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to increase 2.5% in 2011. Similarly, 35.9% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2011 or, subject to 2010 shipper or Supply Corporation notifications, could have been terminated effective in 2011. Based on contract expirations and termination notices received in 2010 for 2011 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to decrease 6.6% in 2011. This expected decrease is due largely to the relative increase in the price of natural gas supplies available at the receipt point on the United States/Canadian border at Niagara compared to the price of supplies at the delivery point of Leidy.

Supply Corporation previously has been successful in marketing and obtaining executed contracts for available transportation capacity (at discounted rates when necessary), though costlier Niagara pricing will make these efforts more challenging in 2011. Supply Corporation expects to add significant incremental contracted transportation capacity in 2012 in connection with the development of the Marcellus Shale by independent producers.

At the beginning of 2011, Empire had service agreements in place for firm transportation capacity totaling up to approximately 686 MDth per day (including capacity on the Empire Connector). 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. 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 2011, most of Empire s firm contracted capacity (91.6%) was contracted as long-term full-year deals. One of those contracts expires during 2011, representing approximately 2.5% of Empire s firm contracted capacity. In addition, Empire has some seasonal (winter-only) contracts that extend for multiple years, representing 2.4% of Empire s firm contracted capacity. None of those multi-year, seasonal contracts expires during 2011. Arrangements for the remaining 6.0% of Empire s firm contracted capacity are single-season or single-year contracts that expire during 2011 or potentially expire early in 2012, depending on whether Empire issues or receives termination notices during 2011. Two single-season or single-year contracts expire during 2011, representing 1.1% of Empire s firm contracted capacity. At the beginning of 2011, the Utility segment accounted for 6.1% of Empire s firm contracted capacity, and the Energy Marketing segment accounted for 2.0% of Empire s firm contracted capacity, with the remaining 91.9% of Empire s firm contracted capacity subject to contracts with nonaffiliated customers.

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 51.4% of the Company s 2010 income from continuing operations and 49.8% of the Company s 2010 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 4.0% of the Company s 2010 income from continuing operations and 3.9% of the Company s 2010 net income available for common stock.

Additional discussion of the Energy Marketing segment appears below under the headings Sources and Availability of Raw Materials, Competition: The Energy Marketing Segment and Seasonality, in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss from continuing operations in 2010. The impact of this net loss from continuing operations in relation to the Company s 2010 income from continuing operations was negative 0.6%. The All Other and Corporate category, including both continuing and discontinued operations, contributed approximately 2.4% of the Company s 2010 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 2010, the Utility segment purchased 67.1 Bcf of gas for delivery to its customers. Gas purchased from producers and suppliers in the southwestern United States and Canada under firm contracts (seasonal and longer) accounted for 53% of these purchases. Purchases of gas under contracts for one month or less accounted for 47% of the Utility segment s 2010 purchases. Purchases from Chevron Natural Gas (16%), Total Gas & Power North America Inc. (12%) and Tenaska Marketing Ventures (10%) accounted for 38% of the Utility s 2010 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2010.

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 Q 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 2010, this segment purchased 59.6 Bcf of gas, including 58.3 Bcf for delivery to its customers. The remaining 1.3 Bcf largely represents gas used in operations. The gas purchased by the Energy Marketing segment originates 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 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 5%, 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 1,859 full-time employees at September 30, 2010. This compares to 1,949 employees in the Company s operations at September 30, 2009.

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.

Executive Officers of the Company as of November 15, 2010(1)

Name and Age (as of November 15, 2010)	Current Company Positions and Other Material Business Experience During Past Five Years
David F. Smith (57)	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; President of Empire from September 2005 through July 2008; and Vice President of the Company from April 2005 through January 2006.
Ronald J. Tanski (58)	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; Treasurer of Distribution Corporation from April 2004 through July 2008; and Senior Vice President of Distribution Corporation from July 2001 through January 2006.
Matthew D. Cabell (52)	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 (57)	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 (58)	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 (41)	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 (51)	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 (55)	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 (50)	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 (51)	Vice President Business Development of the Company since October 2007. Ms. DeCarolis previously served as President of NFR from January 2005 to October 2007; Secretary of NFR from March 2002 to October 2007; and Vice President of NFR from May 2001 to January 2005.
James D. Ramsdell (55)	Senior Vice President of Distribution Corporation since July 2001.

(1) The executive officers serve at the pleasure of the Board of Directors. The information provided relates to the Company and its principal subsidiaries. Many of the executive officers also have served or currently serve as officers or directors of other subsidiaries of the Company.

Item 1A ***Risk Factors***

As a holding company, the Company depends on its operating subsidiaries to meet its financial obligations.

The Company is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, the Company relies exclusively on repayments of principal and interest on intercompany loans made by the Company to its operating subsidiaries and income from dividends and other cash flow from the subsidiaries. Such operating subsidiaries may not generate sufficient net income to pay upstream dividends or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

The Company is dependent on 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 Service (S&P), Moody s Investors Service and Fitch Ratings Service. 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. 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 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 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 is considering, among other things, a proposal to eliminate by 2020 the PCB use authorization for natural gas pipeline systems, and a proposal to eliminate the authorization for storage of PCB-containing equipment for reuse. The EPA projects that it may issue a Notice of Proposed Rulemaking in March 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 have generally been believed to be favorable to utilities, while rising interest rates are generally believed to be unfavorable, because of the levels of debt that utilities may have outstanding. In addition, the Company s authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, the Company s authorized rate of return could be reduced. If interest rates are higher than assumed rates, the Company s ability to earn its authorized rate of return may be adversely impacted.

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

Operations in the Company s Exploration and Production segment are materially dependent on prices received for its oil and natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and natural gas. Oil and natural gas prices can be volatile and can be affected by: weather conditions, including natural disasters; the supply and price of foreign oil and natural gas; the level of consumer product demand; national and worldwide economic conditions, including 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 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 or between futures contracts for natural gas having different delivery dates 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. Additionally, 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 (for example, as a result of increased production of natural gas within the Pipeline and Storage segment s geographic area), then demand for the Company s natural gas storage services driven by that price differential could decrease. 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 in 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. 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.

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 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. The EPA has determined that stationary sources of significant greenhouse gas emissions will be required under the federal Clean Air Act to obtain permits covering such emissions beginning in January 2011. In addition, the U.S. Congress has been considering 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 severance taxes for oil and gas production are also possible. Additionally, legislative initiatives in the U.S. Congress and regulatory studies, proceedings or initiatives at federal or state agencies focused on the hydraulic fracturing process could result in additional permitting, compliance, reporting and disclosure requirements. 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.

Due to the significant cost of insurance coverage for named windstorms in the Gulf of Mexico, the Company determined that it was not economical to purchase insurance to fully cover its exposures related to such storms. It is possible that named windstorms in the Gulf of Mexico could have a material adverse effect on the Company s results of operations, financial condition and cash flows.

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.

In January 2008, the Company entered into an agreement with New Mountain Vantage GP, L.L.C. (New Mountain) and certain parties related to New Mountain, including the California Public Employees Retirement System (collectively, Vantage), to settle a proxy contest pertaining to the election of directors to the Company s Board of Directors at the Company s 2008 Annual Meeting of Stockholders. That settlement agreement expired on September 15, 2009. Vantage or other existing or potential shareholders may engage in proxy solicitations or advance shareholder proposals after the Company s 2011 Annual Meeting of Stockholders, or otherwise attempt to effect changes or acquire control over the Company.

Campaigns by shareholders to effect changes at publicly traded companies are sometimes led by investors seeking to increase short-term shareholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. Responding to proxy contests and other actions by activist shareholders can be costly and time-consuming, disrupting the Company s operations and diverting the attention of the Company s Board of Directors and senior management from the pursuit of business strategies. As a result, shareholder campaigns could adversely affect the Company s results of operations and financial condition.

Item 1B ***Unresolved Staff Comments***

None

Item 2 ***Properties***

General Information on Facilities

The net investment of the Company in property, plant and equipment was $3.5 billion at September 30, 2010. Approximately 59% 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 (39%), is primarily located in California, in the Appalachian region of the United States, and in the shallow waters of the Gulf Coast region of Texas and Louisiana. 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 and improve transmission and distribution facilities for both retail and transportation customers. Net property, plant and equipment has increased $610.9 million, or 21.5%, since 2005. 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, 2010. The net investment in its gas distribution network (including 14,836 miles of distribution pipeline) and its service connections to customers represent approximately 51% and 34%, respectively, of the Utility segment s net investment in property, plant and equipment at September 30, 2010.

The Pipeline and Storage segment had a net investment of $858.2 million in property, plant and equipment at September 30, 2010. Transmission pipeline represents 41% of this segment s total net investment and includes 2,356 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 20% 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 $86.3 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 98,194 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 $1.3 billion at September 30, 2010.

The Utility and Pipeline and Storage segments facilities provided the capacity to meet the Company s 2010 peak day sendout, including transportation service, of 1,608 MMcf, which occurred on January 11, 2010. Withdrawals from storage of 595.4 MMcf provided approximately 37.0% 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, in the Appalachian region of the United States, and in the shallow waters of the Gulf Coast region of Texas and Louisiana. The Company has been increasing its emphasis in the Appalachian region, primarily in the Marcellus Shale, and has been decreasing its emphasis in the Gulf Coast region. Also, Exploration and Production operations were conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada, until the sale of these properties on August 31, 2007. Further discussion of oil and gas producing activities is included in Item 8, Note Q Supplementary Information for Oil and Gas Producing Activities. Note Q sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2010 reserves shown in Note Q 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 seven 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 to determine 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 an engineer registered with the State of Texas (with 12 years of experience in petroleum engineering and six years of experience in the estimation and evaluation of reserves) and a Certified Petroleum Geologist and Geophysicist in the State of Texas (with 32 years of experience in petroleum geosciences and 21 years of experience in the estimation and evaluation of reserves). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2010 and did not identify any problems which would cause it to take exception to those estimates.

The reliable technologies that were utilized in estimating the reserves include wire line open-hole log data, performance data, log cross sections, core data, and statistical analysis. The statistical method utilized production performance from both the Company s and competitor s 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 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.

Seneca s proved developed and undeveloped natural gas reserves increased from 226 Bcf at September 30, 2008 to 249 Bcf at September 30, 2009. This increase is attributed primarily to extensions and discoveries (59.2 Bcf), primarily in the Appalachian region (49.2 Bcf). This increase was partially offset by production of 22.3 Bcf, negative revisions of previous estimates (9.6 Bcf) and sales of minerals in place (4.7 Bcf) in the Gulf Coast region. Seneca s proved developed and undeveloped oil reserves increased from 46,198 Mbbl at September 30, 2008 to 46,587 Mbbl at September 30, 2009. This increase is attributed to purchases of minerals in place (2,115 Mbbl) in the West Coast region, extensions and discoveries (1,213 Mbbl), and revisions of previous estimates (449 Mbbl). These increases were largely offset by production (3,373 Mbbl), primarily occurring in the West Coast region (2,674 Mbbl). On a Bcfe basis, Seneca s proved developed and undeveloped reserves increased from 503 Bcfe at September 30, 2008 to 528 Bcfe at September 30, 2009.

The Company s proved undeveloped (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 undeveloped reserves at September 30, 2010 as a result of its Marcellus Shale reserve additions. The increase in undeveloped 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 Company s total PUD reserves are 25% of total proved reserves at September 30, 2010, up from 16% of total proved reserves at September 30, 2009.

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 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 developed reserves. This represents 19% of the PUD reserves booked at September 30, 2009. In 2011, the Company estimates that it will invest approximately $140 million to develop the PUD reserves. The Company is committed to developing its PUD reserves within five years of being recorded as PUD reserves as required by the SEC s final rule on Modernization of Oil and Gas Reporting.

At September 30, 2010, 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 undeveloped reserves that have been on the books for more than five years. The Company has reduced the concentration of undeveloped reserves in this field from 61% of total field level reserves at September 30, 2005 to 24% of total field level reserves at September 30, 2010. The Company has been actively drilling undeveloped locations in this field for four out of the past five years, drilling 53 undeveloped locations and converting 3.1 million barrels of proved reserves from undeveloped to developed reserves. The undeveloped reserves in this field represent less than 2% of the Company s proved reserves at the corporate level. The Company is committed to drilling the remaining proved undeveloped locations within five years of being recorded as PUD reserves.

At September 30, 2010, the Company had delivery commitments of 34 Bcf. 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		
	2010	**2009**	**2008**
United States			
Gulf Coast Region			
Average Sales Price per Mcf of Gas	$ 5.22	$ 4.54	$ 10.03

Average Sales Price per Barrel of Oil	$ 76.57	$ 54.58	$ 107.27
Average Sales Price per Mcf of Gas (after hedging)	$ 5.51	$ 5.28	$ 9.49
Average Sales Price per Barrel of Oil (after hedging)	$ 77.18	$ 54.58	$ 98.56
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.15	$ 1.36	$ 1.19
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	37	38	38

	For The Year Ended September 30		
	2010	2009	2008
West Coast Region			
Average Sales Price per Mcf of Gas	$ 4.81	$ 3.91	$ 8.71
Average Sales Price per Barrel of Oil	$ 71.72(1)	$ 50.90(1)	$ 98.17(1)
Average Sales Price per Mcf of Gas (after hedging)	$ 7.02	$ 7.37	$ 8.22
Average Sales Price per Barrel of Oil (after hedging)	$ 74.88(1)	$ 67.61(1)	$ 77.64(1)
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.71(1)	$ 1.38(1)	$ 1.76(1)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	54(1)	55(1)	51(1)
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 4.93(2)	$ 5.52	$ 9.73
Average Sales Price per Barrel of Oil	$ 75.81	$ 56.15	$ 97.40
Average Sales Price per Mcf of Gas (after hedging)	$ 6.15	$ 8.69	$ 8.85
Average Sales Price per Barrel of Oil (after hedging)	$ 75.81	$ 56.15	$ 97.40
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.73(2)	$ 0.87	$ 0.70
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	45(2)	24	22
Total Company			
Average Sales Price per Mcf of Gas	$ 5.01	$ 4.79	$ 9.70
Average Sales Price per Barrel of Oil	$ 72.54	$ 51.69	$ 99.64
Average Sales Price per Mcf of Gas (after hedging)	$ 6.04	$ 6.94	$ 9.05
Average Sales Price per Barrel of Oil (after hedging)	$ 75.25	$ 64.94	$ 81.75
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.24	$ 1.27	$ 1.36
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	136	116	111

(1) The Midway Sunset North fields (which exceed 15% of total reserves) contributed 25 MMcfe, 28 MMcfe and 26 MMcfe of production per day, at average sales prices (per bbl) of $69.68 ($75.75 after hedging), $48.87 ($75.47 after hedging), and $95.82 ($63.90 after hedging) for 2010, 2009 and 2008, respectively. Lifting costs (per Mcfe) were $1.90, $1.34 and $2.01 for 2010, 2009 and 2008, respectively.

(2) The Marcellus Shale fields (which exceed 15% of total reserves) contributed 20 MMcfe of daily production at an average sales price (per Mcfe) of $4.56 (before hedging) and lifting costs (per Mcfe) of $0.55 during 2010. The Company did not hedge Marcellus Shale production during 2010.

Productive Wells

	Gulf Coast Region		West Coast Region		Appalachian Region		Total Company	
At September 30, 2010	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**

Productive Wells	Gross	19	40	1,542	2,974	6	2,993	1,588
Productive Wells	Net	10	13	1,508	2,865	5	2,875	1,526

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Developed and Undeveloped Acreage

At September 30, 2010	Gulf Coast Region	West Coast Region	Appalachian Region	Total Company
Developed Acreage				
Gross	74,248	13,830	522,158	610,236
Net	49,436	11,622	498,701	559,759
Undeveloped Acreage				
Gross	90,573	5,190	430,865	526,628
Net	75,427	934	412,464	488,825
Total Developed and Undeveloped Acreage				
Gross	164,821	19,020	953,023	1,136,864
Net	124,863	12,556	911,165	1,048,584

As of September 30, 2010, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 61,167 acres in 2011 (45,775 net acres), 9,055 acres in 2012 (7,634 net acres), 40,173 acres in 2013 (39,151 net acres), and 66,877 acres thereafter (58,716 net acres). The remaining 349,356 gross acres (337,549 net acres) represent non-expiring oil and gas rights owned by the Company.

Drilling Activity

	Productive			Dry		
For the Year Ended September 30	2010	2009	2008	2010	2009	2008
United States						
Gulf Coast Region						
Net Wells Completed						
Exploratory	0.29	0.29	1.14			0.37
Development					0.30	
West Coast Region						
Net Wells Completed						
Exploratory			1.00			
Development	41.72	27.00	62.00			1.00
Appalachian Region						
Net Wells Completed						
Exploratory	33.00	2.00	8.00	2.00	3.00	1.00
Development	131.55	250.00	186.00	3.00		
Total United States						
Net Wells Completed						
Exploratory	33.29	2.29	10.14	2.00	3.00	1.37
Development	173.27	277.00	248.00	3.00	0.30	1.00

Present Activities

At September 30, 2010	Gulf Coast Region	West Coast Region	Appalachian Region	Total Company
Wells in Process of Drilling(1)				
Gross	1.00		85.00	86.00
Net	0.20		66.62	66.82

(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.

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

On July 1, 2010, the Company issued a total of 3,600 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, 400 shares to each such director. All of these unregistered shares were issued under the Company s Retainer Policy for Non-Employee Directors as partial consideration for such directors services during the quarter ended September 30, 2010. 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, 2010	8,383	$ 47.90		6,971,019
Aug. 1-31, 2010	10,906	$ 45.60		6,971,019
Sept. 1-30, 2010	161,520	$ 51.52		6,971,019

Total	180,809	$	51.00	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 or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended September 30, 2010, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 180,809 shares purchased other than through a publicly announced share repurchase program, 26,277 were purchased for the Company s 401(k) plans and 154,532 were purchased as a result of shares tendered to the Company by holders of stock options or shares of restricted stock.

(b) In December 2005, the Company s Board of Directors authorized the repurchase of up to eight million shares of the Company s common stock. The Company completed the repurchase of the eight million shares during 2008. In September 2008, the Company s Board of Directors authorized the repurchase of an additional eight million shares of the Company s common stock. The Company, however, stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. 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.

Item 6 ***Selected Financial Data***

	Year Ended September 30				
	2010	2009	2008	2007	2006
	(Thousands, except per share amounts and number of registered shareholders)				
Summary of Operations					
Operating Revenues	$ 1,760,503	$ 2,051,543	$ 2,396,837	$ 2,034,400	$ 2,236,369
Operating Expenses:					
Purchased Gas	658,432	997,216	1,238,405	1,019,349	1,269,109
Operation and Maintenance	394,569	401,200	429,394	395,704	395,226
Property, Franchise and Other Taxes	75,852	72,102	75,525	70,589	69,129
Depreciation, Depletion and Amortization	191,199	170,620	169,846	157,142	151,220
Impairment of Oil and Gas Producing Properties		182,811			
	1,320,052	1,823,949	1,913,170	1,642,784	1,884,684
Operating Income	440,451	227,594	483,667	391,616	351,685
Other Income (Expense):					
Income from Unconsolidated Subsidiaries	2,488	3,366	6,303	4,979	3,583
Impairment of Investment in Partnership		(1,804)			
Other Income	3,638	8,200	7,164	6,995	5,544
Interest Income	3,729	5,776	10,815	1,550	9,409
Interest Expense on Long-Term Debt	(87,190)	(79,419)	(70,099)	(68,446)	(72,629)
Other Interest Expense	(6,756)	(7,370)	(3,271)	(4,155)	(4,050)
Income from Continuing Operations Before Income Taxes	356,360	156,343	434,579	332,539	293,542
Income Tax Expense	137,227	52,859	167,672	131,291	108,241
Income from Continuing Operations	219,133	103,484	266,907	201,248	185,301
Discontinued Operations:					
Income (Loss) from Operations, Net of Tax	470	(2,776)	1,821	15,906	(47,210)

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		(47,210)
Net Income Available for Common Stock	$	225,913	$	100,708	$	268,728	$	337,455	$	138,091

	Year Ended September 30				
	2010	2009	2008	2007	2006
	(Thousands, except per share amounts and number of registered shareholders)				
Per Common Share Data					
Basic Earnings from Continuing Operations per Common Share	$ 2.70	$ 1.29	$ 3.25	$ 2.42	$ 2.21
Diluted Earnings from Continuing Operations per Common Share	$ 2.65	$ 1.28	$ 3.16	$ 2.36	$ 2.16
Basic Earnings per Common Share(1)	$ 2.78	$ 1.26	$ 3.27	$ 4.06	$ 1.64
Diluted Earnings per Common Share(1)	$ 2.73	$ 1.25	$ 3.18	$ 3.96	$ 1.61
Dividends Declared	$ 1.36	$ 1.32	$ 1.27	$ 1.22	$ 1.18
Dividends Paid	$ 1.35	$ 1.31	$ 1.26	$ 1.21	$ 1.17
Dividend Rate at Year-End	$ 1.38	$ 1.34	$ 1.30	$ 1.24	$ 1.20
At September 30:					
Number of Registered Shareholders	15,549	16,098	16,544	16,989	17,767
Net Property, Plant and Equipment					
Utility	$ 1,165,240	$ 1,144,002	$ 1,125,859	$ 1,099,280	$ 1,084,080
Pipeline and Storage	858,231	839,424	826,528	681,940	674,175
Exploration and Production(2)	1,338,956	1,041,846	1,095,960	982,698	1,002,265
Energy Marketing	436	71	98	102	59
All Other(3)	81,103	99,787	98,338	106,637	108,333
Corporate	6,263	6,915	7,317	7,748	8,814
Total Net Plant	$ 3,450,229	$ 3,132,045	$ 3,154,100	$ 2,878,405	$ 2,877,726
Total Assets	$ 5,105,625	$ 4,769,129	$ 4,130,187	$ 3,888,412	$ 3,763,748
Capitalization					
Comprehensive Shareholders Equity	$ 1,745,971	$ 1,589,236	$ 1,603,599	$ 1,630,119	$ 1,443,562
Long-Term Debt, Net of Current Portion	1,049,000	1,249,000	999,000	799,000	1,095,675
Total Capitalization	$ 2,794,971	$ 2,838,236	$ 2,602,599	$ 2,429,119	$ 2,539,237

(1) Includes discontinued operations.

(2) Includes net plant of SECI discontinued operations as follows: $0 for 2010, 2009, 2008 and 2007, and $88,023 for 2006.

(3) Includes net plant of landfill gas discontinued operations as follows: $0 for 2010, $9,296 for 2009, $11,870 for 2008, $12,516 for 2007, and $13,206 for 2006.

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) 2010 and projected 2011 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, 2010 compared to the year ended September 30, 2009, the Company experienced an increase in earnings of $125.2 million. Earnings from continuing operations increased $115.6 million and earnings from discontinued operations increased $9.6 million. From a continuing operations perspective, the earnings increase was primarily driven by the non-recurrence of an impairment charge of $182.8 million ($108.2 million after tax) recorded in the Exploration and Production segment during the year ended September 30, 2009. 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. Such costs are subject to a quarterly ceiling test prescribed by SEC Regulation S-X Rule 4-10 that determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. At December 31, 2008, due to significant declines in crude oil and natural gas commodity prices (and using the SEC full cost rules then in effect), the book value of the Company s oil and gas properties exceeded the ceiling, resulting in the impairment charge mentioned above. For further discussion of the ceiling test results at September 30, 2010 and a sensitivity analysis to changes in crude oil and natural gas commodity prices, refer to the Critical Accounting Estimates section below. For further discussion of the Company s earnings, refer to the Results of Operations section below.

The Company continues to focus on the development of its Marcellus Shale acreage in the Appalachian region of its Exploration and Production segment. 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 approximately 745,000 net acres within the Marcellus Shale area, with a majority of the acreage 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 150 Bcf at September 30, 2009 to 331 Bcf at September 30, 2010. 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, 2010, the Company spent $332.4 million towards the development of the Marcellus Shale. This included paying $71.8 million in March 2010 for two tracts of leasehold acreage (consisting of approximately 18,000 net acres) in Tioga and Potter Counties in Pennsylvania. These tracts are geologically and geographically similar to the Company s existing Marcellus Shale acreage in the area, and will help the Company continue its developmental drilling program.

The Company has engaged Jefferies & Company to explore joint-venture opportunities across its Marcellus Shale acreage in its Exploration and Production segment. It is the Company s goal to ramp up Marcellus Shale development faster than its current plans. By entering into a joint-venture agreement, the Company expects to enhance shareholder value by shifting a significant portion of the early drilling costs to a minority-interest partner while still allowing the Company to continue operating across most of its acreage. The Company s position in the Marcellus Shale provides a competitive advantage for a potential joint- venture partner as a majority of the acreage is held in fee, carrying no royalty and no lease expirations, and large, contiguous acreage blocks allow for operating- and cost-efficiency through multi-well pad drilling. The Company will forgo any joint-venture opportunities that do not enhance shareholder value when compared to its current growth plans.

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 year, 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. Empire and Supply Corporation have seen transportation volumes decrease as a result of this situation. 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 been able to meet its capital expenditure needs for all of the above projects by using cash from operations. The Company had $395.2 million in Cash and Temporary Cash Investments at September 30, 2010, as shown on the Company s Consolidated Balance Sheet. For fiscal 2011, the Company expects that it will be able to use cash on hand and cash from operations as its first means of financing capital expenditures, with short-term borrowings being its next source of funding. It is not expected that long-term financing will be required to meet capital expenditure needs until the later part of fiscal 2011 or in fiscal 2012.

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 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 currently has a moratorium in place that prevents hydraulic fracturing of new horizontal wells in the Marcellus Shale. However, due to the small amount of Marcellus Shale acreage owned by the Company in New York State, the moratorium is 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.

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. This sale resulted in a $6.3 million gain, net of tax. 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 those operations as discontinued operations in September 2010.

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. In addition to the 23 million board feet mentioned above, the Company expects to sell an additional 17 million board feet of logs to the purchaser over a five-year period, during which time the Company anticipates receiving up to an additional $10 million in proceeds. There was not a material impact to earnings from this sale.

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.

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, 2010, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $269.6 million. The 12-month average of the first day of the month price for crude oil for each month during 2010, based on posted Midway Sunset prices, was $69.64 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2010, based on the quoted Henry Hub spot price for natural gas, was $4.41 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 2010.) If natural gas prices used in the ceiling test calculation at September 30, 2010 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $152.9 million. If crude oil prices used in the ceiling test calculation at September 30, 2010 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $221.6 million. If both natural gas and crude oil prices used in the ceiling test calculation at September 30, 2010 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 $104.8 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 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 93% of the Company s total pension and post-retirement benefit costs for the years ended September 30, 2010 and 2009.

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 5.50% in 2009 to 4.75% in 2010. The change in the discount rate from 2009 to 2010 increased the Retirement Plan projected benefit obligation by $75.1 million and the accumulated post-retirement benefit obligation by $39.4 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligation and the accumulated post-retirement benefit obligation. For 2010, the actual return on plan assets exceeded the expected return, which improved the funded status of the Retirement Plan ($3.3 million) as well as the VEBA trusts and 401(h) accounts ($4.1 million). The actual versus expected benefit payments for 2010 caused a decrease of $4.3 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 9 years for the Retirement Plan and 8 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

2010 Compared with 2009

The Company s earnings were $225.9 million in 2010 compared with earnings of $100.7 million in 2009. As previously discussed, 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. 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 event in 2010 and several events in 2009, including:

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.

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.

2009 Compared with 2008

The Company s earnings were $100.7 million in 2009 compared with earnings of $268.7 million in 2008. The Company s earnings from continuing operations were $103.5 million in 2009 compared with $266.9 million in 2008. The Company recorded a loss from discontinued operations of $2.8 million in 2009 compared with earnings from discontinued operations of $1.8 million in 2008. Discontinued operations in 2009 and 2008 consisted of the Company s landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. The decrease in earnings from continuing operations of $163.4 million is primarily the result of lower earnings in the Exploration and Production, Pipeline and Storage and Utility segments and the All Other category, slightly offset by a lower loss in the Corporate category and higher earnings in the Energy Marketing segment, as shown in the table below. The loss from discontinued operations in 2009 compared to earnings from discontinued operations in 2008 reflects the recognition of $2.8 million of impairment charges in 2009 related to certain landfill gas assets. Earnings from continuing operations and discontinued operations were impacted by the 2009 events discussed above and the following 2008 event:

2008 Event

A $0.6 million gain in the All Other category associated with the sale of Horizon Power s gas-powered turbine.

Earnings (Loss) by Segment

	Year Ended September 30		
	2010	**2009**	**2008**
		(Thousands)	
Utility	$ 62,473	$ 58,664	$ 61,472
Pipeline and Storage	36,703	47,358	54,148
Exploration and Production	112,531	(10,238)	146,612
Energy Marketing	8,816	7,166	5,889
Total Reported Segments	220,523	102,950	268,121
All Other	3,396	705	3,958
Corporate	(4,786)	(171)	(5,172)
Total Earnings from Continuing Operations	219,133	103,484	266,907
Earnings (Loss) from Discontinued Operations	6,780	(2,776)	1,821
Total Consolidated	$ 225,913	$ 100,708	$ 268,728

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2010	2009	2008
		(Thousands)	
Retail Revenues:			
Residential	$ 583,443	$ 850,088	$ 876,677
Commercial	81,110	128,520	135,361
Industrial	5,697	7,213	7,419
	670,250	985,821	1,019,457
Off-System Sales	29,135	3,740	58,225
Transportation	109,675	111,483	113,901
Other	10,730	11,980	18,686
	$ 819,790	$ 1,113,024	$ 1,210,269

Utility Throughput   million cubic feet (MMcf)

	Year Ended September 30		
	2010	2009	2008
Retail Sales:			
Residential	54,012	58,835	57,463
Commercial	8,203	9,551	9,769
Industrial	646	515	552
	62,861	68,901	67,784
Off-System Sales	5,899	513	5,686
Transportation	60,105	59,751	64,267
	128,865	129,165	137,737

Degree Days

	Percent (Warmer) Colder Than

Year Ended September 30		**Normal**	**Actual**	**Normal**	**Prior Year**
2010(1):	Buffalo	6,692	6,292	(6.0)%	(6.1)%
	Erie	6,243	5,947	(4.7)%	(3.7)%
2009(2):	Buffalo	6,692	6,701	0.1%	6.8%
	Erie	6,243	6,176	(1.1)%	6.9%
2008(3):	Buffalo	6,729	6,277	(6.7)%	0.1%
	Erie	6,277	5,779	(7.9)%	(3.8)%

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

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

(3) Percents compare actual 2008 degree days to normal degree days and actual 2008 degree days to actual 2007 degree days.

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. Margins 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.

2009 Compared with 2008

Operating revenues for the Utility segment decreased $97.2 million in 2009 compared with 2008. This decrease largely resulted from a $54.5 million decrease in off-system sales revenue (see discussion below), a $33.6 million decrease in retail gas sales revenues, a $2.4 million decrease in transportation revenues, and a $6.7 million decrease in other operating revenues.

The decrease in retail gas sales revenues of $33.6 million was largely a function of the recovery of 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 much lower cost of purchased gas. See further discussion of purchased gas below under the heading Purchased Gas. The decrease in transportation revenues of $2.4 million was primarily due to a 4.5 Bcf decrease in transportation throughput, largely the result of customer conservation efforts and the poor economy.

In the New York jurisdiction, the NYPSC issued an order providing for an annual rate increase of $1.8 million beginning December 28, 2007. As part of this rate order, a rate design change was adopted that shifts a greater amount of cost recovery into the minimum bill amount, thus spreading the recovery of such costs more evenly throughout the year. As a result of this rate order, retail and transportation revenues for 2009 were $2.2 million lower than revenues for 2008.

The Utility segment had off-system sales revenues of $3.7 million and $58.2 million for 2009 and 2008, respectively. 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 in 2009 and 2008. The decrease in off-system sales revenue stemmed from Order No. 717 (Final Rule), as discussed above.

The decrease in other operating revenues of $6.7 million is largely related to amounts recorded in 2008 pursuant to rate settlements approved by the NYPSC. In accordance with these settlements, Distribution Corporation was allowed to utilize certain refunds from upstream pipeline companies and certain other credits (referred to as the cost mitigation reserve) to offset certain specific expense items. In 2008, Distribution Corporation utilized $5.6 million of the cost mitigation reserve, which increased other operating revenues, to recover previous undercollections of pension expenses. In 2009, Distribution Corporation utilized only $0.2 million of the cost mitigation reserve. The impact of this $5.4 million decrease in other operating revenues was offset by an equal decrease to operation and maintenance expense (thus there was no earnings impact).

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 $428.4 million, $713.2 million and $800.5 million of Purchased Gas Expense during 2010, 2009 and 2008, 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 six 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 $7.13 per Mcf in 2010, a decrease of 13% from the average cost of $8.17 per Mcf in 2009. The average cost of purchased gas in 2009 was 27% lower than the average cost of $11.23 per Mcf in 2008. Additional discussion of the Utility segment s gas purchases appears under the heading Sources and Availability of Raw Materials in Item 1.

Earnings

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.

In the New York jurisdiction, earnings increased by $1.8 million. The positive earnings impact associated with lower operating expenses of $1.5 million (primarily a decrease in bad debt expense slightly offset by an increase in personnel costs) and routine regulatory adjustments ($1.4 million) were partially offset by a $1.2 million decrease in late payment revenue (due to lower gas costs) and higher income tax expense of $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 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.

In the Pennsylvania jurisdiction, earnings increased by $2.0 million. The positive earnings impact associated with a lower effective tax rate ($5.1 million) and lower operating expenses of $2.8 million were the main factors in the earnings increase. 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 primarily attributable to a decrease in bad debt expense. These factors were partially offset by lower usage per account ($2.1 million), higher interest expense ($2.1 million), warmer weather ($0.8 million) and routine regulatory true-up adjustments ($0.2 million). The phrase usage per account refers to average gas consumption per account after factoring out any impact that weather may have had on consumption. 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.

2009 Compared with 2008

The Utility segment s earnings in 2009 were $58.7 million, a decrease of $2.8 million when compared with earnings of $61.5 million in 2008.

In the New York jurisdiction, earnings decreased by $3.0 million. This was primarily due to an increase in interest expense ($2.9 million) stemming from the borrowing by the New York jurisdiction of Distribution Corporation of a portion of the Company s April 2009 debt issuance. The April 2009 debt was issued at a significantly higher interest rate than the interest rates on debt that had matured in March 2009. The negative earnings impact of the December 28, 2007 rate order discussed above ($1.4 million) and routine regulatory adjustments ($0.7 million) also contributed to the decrease. The decrease was partially offset by a $2.6 million overall reduction in operating expenses (mostly other post-retirement benefits and pension expense).

In 2009, the WNC reduced earnings by approximately $0.2 million, as the weather was colder than normal. In 2008, the WNC preserved earnings of approximately $2.5 million, as the weather was warmer than normal.

In the Pennsylvania jurisdiction, earnings increased by $0.2 million. This was primarily due to the positive earnings impact of colder weather ($2.1 million), routine regulatory adjustments ($0.5 million) and lower operating expenses ($0.9 million). A decrease in normalized usage per account ($2.3 million), a higher effective tax rate ($1.4 million) and an increase in interest expense ($0.2 million) partially offset these increases. The phrase usage per account refers to the average gas consumption per customer account after factoring out any impact that weather may have had on consumption.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2010	2009 (Thousands)	2008
Firm Transportation	$ 139,324	$ 139,034	$ 122,321
Interruptible Transportation	1,863	3,175	4,330
	141,187	142,209	126,651
Firm Storage Service	66,593	66,711	67,020
Interruptible Storage Service	78	20	14
	66,671	66,731	67,034
Other	11,025	10,333	22,871
	$ 218,883	$ 219,273	$ 216,556

Pipeline and Storage Throughput (MMcf)

	Year Ended September 30		
	2010	2009	2008
Firm Transportation	296,907	348,294	353,173
Interruptible Transportation	4,459	3,888	5,197
	301,366	352,182	358,370

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 (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. Offsetting the decrease was an increase in efficiency gas revenues of $1.3 million (reported as a part of other revenue in the table above) 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. Under Supply Corporation s tariff with shippers, Supply Corporation is allowed to retain a set percentage of shipper-supplied gas to cover compressor fuel costs 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 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. The reason shippers are seeking lower priced gas supply is primarily 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 proposed 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. Much of the impact of lower volumes is offset by the straight fixed-variable rate design utilized by Supply Corporation and Empire. However, 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.

2009 Compared with 2008

Operating revenues for the Pipeline and Storage segment increased $2.7 million in 2009 as compared with 2008. The increase was primarily due to a $15.6 million increase in transportation revenue primarily due to higher revenues from the Empire Connector and new contracts for transportation service. Partially offsetting this increase, efficiency gas revenues decreased $11.5 million. The majority of this decrease was due to significantly lower gas prices in 2009 as compared to 2008.

Earnings

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.

2009 Compared with 2008

The Pipeline and Storage segment s earnings in 2009 were $47.4 million, a decrease of $6.7 million when compared with earnings of $54.1 million in 2008. The decrease was primarily due to the earnings impact associated with a decrease in efficiency gas revenues ($7.5 million), as discussed above. In addition, higher interest expense ($5.1 million), higher depreciation expense ($1.5 million), and a decrease in the allowance for funds used during construction ($2.0 million) also contributed to the decrease in earnings. The increase in interest expense can be attributed to higher debt balances and a higher average interest rate on borrowings. The increase in the average interest rate stems from the Company s April 2009 debt issuance. The increase in depreciation expense can be attributed primarily to a revision of accumulated depreciation combined with the increased depreciation associated with placing the Empire Connector in service in December 2008. The decrease in the allowance for funds used during construction was due to completion of the Empire Connector project in December 2008. Whereas the allowance for funds used during construction related to the Empire Connector project was recorded throughout 2008, it was only recorded for three months in 2009. These earnings decreases were partially offset by the earnings impact associated with higher transportation revenues ($9.7 million), as discussed above.

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30 2010	2009	2008
		(Thousands)	
Gas (after Hedging)	$ 183,327	$ 154,582	$ 202,153
Oil (after Hedging)	242,303	219,046	250,965
Gas Processing Plant	29,369	24,686	49,090
Other	820	432	(944)
Intrasegment Elimination(1)	(17,791)	(15,988)	(34,504)
Operating Revenues	$ 438,028	$ 382,758	$ 466,760

(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.

Production

	Year Ended September 30 2010	2009	2008
Gas Production *(MMcf)*			
Gulf Coast	10,304	9,886	11,033
West Coast	3,819	4,063	4,039
Appalachia	16,222	8,335	7,269
Total Production	30,345	22,284	22,341
Oil Production *(Mbbl)*			
Gulf Coast	502	640	505
West Coast	2,669	2,674	2,460
Appalachia	49	59	105
Total Production	3,220	3,373	3,070

Average Prices

	Year Ended September 30		
	2010	2009	2008
Average Gas Price/Mcf			
Gulf Coast	$ 5.22	$ 4.54	$ 10.03
West Coast	$ 4.81	$ 3.91	$ 8.71
Appalachia	$ 4.93	$ 5.52	$ 9.73
Weighted Average	$ 5.01	$ 4.79	$ 9.70
Weighted Average After Hedging(1)	$ 6.04	$ 6.94	$ 9.05
Average Oil Price/Barrel (bbl)			
Gulf Coast	$ 76.57	$ 54.58	$ 107.27
West Coast(2)	$ 71.72	$ 50.90	$ 98.17
Appalachia	$ 75.81	$ 56.15	$ 97.40
Weighted Average	$ 72.54	$ 51.69	$ 99.64
Weighted Average After Hedging(1)	$ 75.25	$ 64.94	$ 81.75

(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.

(2) Includes low gravity oil which generally sells for a lower price.

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.

2009 Compared with 2008

Operating revenues for the Exploration and Production segment decreased $84.0 million in 2009 as compared with 2008. Gas production revenue after hedging decreased $47.6 million primarily due to a $2.11 per Mcf decrease in weighted average prices after hedging. Gas production was virtually flat with the prior year as production decreases in the Gulf Coast region were substantially offset by production increases in the Appalachian region. The decrease in gas production that occurred in the Gulf Coast region (1,147 MMcf) was a result of lingering shut-ins caused by Hurricanes Edouard, Gustav and Ike in September 2008. While Seneca s properties sustained only superficial damage from the hurricanes, two significant producing properties were shut-in for a significant portion of the current fiscal year due to repair work on third party pipelines and onshore processing facilities. One of the properties was back on line by March 31, 2009 and the other property was back on line by the end of April 2009. The increase in gas production in the Appalachian region of 1,066 MMcf resulted from additional wells drilled throughout fiscal 2008 that came on line in 2009. Oil production revenue after hedging decreased $31.9 million due to a $16.81 per barrel decrease in weighted average prices after hedging, which more than offset an increase in oil production of 303,000 barrels (primarily from the West Coast and Gulf Coast regions). In addition, there was a $5.9 million decrease in gross processing plant revenues (net of eliminations) due to a reduction in the commodity prices of residual gas and liquids sold at Seneca s processing plants in the West Coast and Appalachian regions.

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

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 in the Overview section. 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.

2009 Compared with 2008

The Exploration and Production segment s loss for 2009 was $10.2 million, compared with earnings of $146.6 million for 2008, a decrease of $156.8 million. The decrease in earnings is primarily the result of an impairment charge of $108.2 million, as discussed above. In addition, lower crude oil prices, lower natural gas prices, and lower natural gas production decreased earnings by $36.9 million, $30.6 million, and $0.3 million, respectively, while higher crude oil production increased earnings by $16.1 million. Lower interest income ($5.5 million) and higher operating expenses ($1.7 million) further reduced earnings. In addition, there was a $3.8 million decrease in earnings caused by a reduction in the commodity prices of residual gas and liquids sold at Seneca s processing plants in the West Coast and Appalachian regions. The decrease in interest income is due to lower interest rates and lower temporary cash investment balances. The increase in operating expenses is due to an increase in bad debt expense as a result of a customer s bankruptcy filing, and higher personnel costs in the Appalachian region. These earnings decreases were partially offset by lower interest expense ($5.4 million), lower lease operating costs ($2.6 million), lower depletion expense ($0.9 million), and lower income tax expense ($4.2 million). The decline in interest expense is primarily due to a lower average amount of debt outstanding. The reduction in lease operating expenses is primarily due to a reduction in steam fuel costs in the West Coast region and lower production taxes in the Gulf Coast region. The decrease in depletion is primarily due to a lower full cost pool balance after the impairment charge taken during the quarter ended December 31, 2008.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2010	2009	2008
		(Thousands)	
Natural Gas (after Hedging)	$ 344,077	$ 398,205	$ 551,243
Other	725	116	(11)
	$ 344,802	$ 398,321	$ 551,232

Energy Marketing Volume

	Year Ended September 30		
	2010	2009	2008
Natural Gas (MMcf)	58,299	60,858	56,120

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.

2009 Compared with 2008

Operating revenues for the Energy Marketing segment decreased $152.9 million in 2009 as compared with 2008. The decrease is primarily due to lower gas sales revenue, due to a lower average price of natural gas that was recovered through revenues. This decline was somewhat offset by an increase in volume sold. The increase in sales volume is largely attributable to colder weather as well as an increase in 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

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.

2009 Compared with 2008

The Energy Marketing segment s earnings in 2009 were $7.2 million, an increase of $1.3 million when compared with earnings of $5.9 million in 2008. Higher margin of $1.5 million combined with lower operating costs of $0.4 million (primarily due to a decline in bad debt expense) are responsible for the increase in earnings. These increases were partially offset by higher income tax expense of $0.4 million in 2009 as compared to 2008. The increase in margin was primarily driven by lower pipeline transportation fuel costs due to lower natural gas commodity prices, an unfavorable pipeline imbalance resolution in fiscal 2008 that did not recur in fiscal 2009, and improved average margins per Mcf, partially offset by higher pipeline reservation charges related to additional storage capacity.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of Highland, Seneca s Northeast Division, Midstream Corporation, Horizon Power, former International segment activity and corporate operations. Highland and Seneca s Northeast Division market timber from their 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 net of 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 activity primarily consists of equity method investments in Seneca Energy, Model City and ESNE. Horizon Power has a 50% ownership interest in each of these entities. The income from these equity method investments is reported as Income from Unconsolidated Subsidiaries on the Consolidated Statements of Income. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. On November 1, 2010, ESNE stopped all electricity generation operations. The turbines and other assets will be sold and the building will be dismantled. ESNE generated electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. 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 net of tax). 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. Refer to Item 8 at Note J Discontinued Operations for further details.

Earnings

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 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).

2009 Compared with 2008

All Other and Corporate operations had earnings from continuing operations of $0.5 million in 2009, an increase of $1.7 million compared with a loss from continuing operations of $1.2 million for 2008. The increase was due to lower operating costs ($3.8 million), lower income tax expenses ($4.6 million), lower depreciation and depletion ($0.4 million) and higher other income ($0.7 million). In 2008, the proxy contest with New Mountain Vantage GP, L.L.C. led to an increase in operating costs, which did not recur in 2009. In addition, a gain on life insurance policies held by the Company ($2.3 million) further increased earnings. The reduction in depreciation and depletion expense is due to a decrease in timber harvested from Company owned lands. The increase in other income is primarily due to an increase in the value of corporate owned life insurance policies. These earnings increases were partially offset by higher interest expense ($3.4 million), lower income from Horizon Power s investments in unconsolidated subsidiaries ($2.0 million), lower margins from lumber, log, and timber rights sales ($2.5 million) and lower interest income ($0.6 million). The decrease in margins from lumber, log and timber rights sales is a result of a decline in revenues due to unfavorable market conditions. The increase in interest expense was primarily the result of higher borrowings at a higher interest rate (mostly due to the $250 million of 8.75% notes that were issued in April 2009). The decrease in interest income is largely due to lower rates on cash investment balances. In addition, during 2009, ESNE, an unconsolidated subsidiary of Horizon Power, recorded an impairment charge of $3.6 million. Horizon Power s 50% share of the impairment was $1.8 million ($1.1 million on an after tax basis). The impairment charge of $3.6 million recorded by ESNE during 2009 (as discussed above) was driven by a significant decrease in run time for the plant given the economic downturn and the resulting decrease in demand for electric power. Also, Horizon Power recognized a gain on the sale of a turbine ($0.6 million) during 2008 that did not recur in 2009.

INTEREST INCOME

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.

Interest income was $5.0 million lower in 2009 as compared to 2008. Lower cash investment balances in the Exploration and Production segment and lower interest rates on such investments were the primary factors contributing to this decrease.

OTHER INCOME

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.

Other income was $1.0 million higher in 2009 as compared to 2008. This increase was primarily due to a death benefit gain on corporate-owned life insurance policies of $2.3 million recognized during the first quarter of 2009. In addition, there was a larger year-over-year increase in the value of corporate-owned life insurance policies ($1.8 million). This increase is partially offset by a $2.2 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, Horizon Power recognized a $0.9 million pre-tax gain on the sale of a turbine during 2008 that did not recur in 2009.

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 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.

Interest on long-term debt increased $9.3 million in 2009 as compared to 2008. The increase in 2009 was primarily the result of a higher average amount of long-term debt outstanding combined with higher average interest rates due to the April 2009 debt issuance discussed above. This increase was partially offset by the repayment of $100 million of 6% medium-term notes that matured in March 2009.

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 2009.

Other interest charges increased $4.1 million in 2009 compared to 2008. The increase in 2009 was primarily caused by a $2.3 million increase in interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment s New York jurisdiction combined with a $0.7 million decrease in the allowance for borrowed funds used during construction related to the Empire Connector project. In addition, there was an increase due to an audit adjustment on a state tax return from 2008 ($0.4 million).

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		
	2010	**2009**	**2008**
		(Millions)	
Provided by Operating Activities	$ 459.7	$ 611.8	$ 482.8
Capital Expenditures	(455.8)	(313.6)	(397.7)
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		
Cash Held in Escrow		(2.0)	58.4
Net Proceeds from Sale of Oil and Gas Producing Properties		3.6	5.9
Other Investing Activities	(0.3)	(2.8)	4.4
Reduction of Long-Term Debt		(100.0)	(200.0)
Net Proceeds from Issuance of Long-Term Debt		247.8	296.6
Net Proceeds from Issuance of Common Stock	26.0	28.2	17.4
Dividends Paid on Common Stock	(109.5)	(104.2)	(103.7)
Excess Tax Benefits Associated with Stock- Based Compensation Awards	13.2	5.9	16.3
Shares Repurchased under Repurchase Plan			(237.0)
Net Increase (Decrease) in Cash and Temporary Cash Investments	$ (12.9)	$ 339.8	$ (56.6)

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, income or loss from unconsolidated subsidiaries net of cash distributions and 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. 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 $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.

Net cash provided by operating activities totaled $611.8 million in 2009, an increase of $129.0 million compared with the $482.8 million provided by operating activities in 2008. The increase 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 is reflected in Amounts Payable to Customers on the Company s Consolidated Balance Sheet at September 30, 2009. At September 30, 2008, the Company s Utility segment was in an under-recovery position.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company s expenditures from continuing operations for long-lived assets totaled $501.4 million, $341.4 million and $414.4 million in 2010, 2009 and 2008, respectively. The table below presents these expenditures:

	Year Ended September 30		
	2010	**2009**	**2008**
		(Millions)	
Utility:			
Capital Expenditures	$ 58.0	$ 56.2	$ 57.5
Pipeline and Storage:			
Capital Expenditures	37.9	52.5(3)	165.5(3)
Exploration and Production:			
Capital Expenditures	398.2(1)(2)	188.3(2)	192.2
Investment in Subsidiary		34.9(4)	
All Other and Corporate:			
Capital Expenditures	7.3(2)	9.8(2)	1.6
Eliminations		(0.3)(5)	(2.4)(6)
Total Expenditures from Continuing Operations	$ 501.4(7)	$ 341.4(7)	$ 414.4(7)

(1) Amount for 2010 includes $55.5 million of accrued capital expenditures, the majority of which was in the Appalachian region. This amount has been excluded from the Consolidated Statement of Cash Flows at September 30, 2010 since it represents a non-cash investing activity at that date.

(2) 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.

(3) 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 shown in the table above, 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.

(4) Investment amount is net of $4.3 million of cash acquired.

(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) Represents $2.4 million of capital expenditures included in the Appalachian region of the Exploration and Production segment for the purchase of storage facilities, buildings, and base gas from Supply Corporation during the quarter ended March 31, 2008.

(7) Excludes expenditures for long-lived assets associated with discontinued operations as follows: $0.1 million for 2010, $0.2 million for 2009, and $0.1 million for 2008.

Utility

The majority of the Utility capital expenditures for 2010, 2009 and 2008 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 2010 were made for additions, improvements, and replacements to this segment s transmission and gas storage systems. The Pipeline and Storage capital expenditure amounts for 2010 also include $6.0 million spent on the Lamont Project, discussed below. The majority of the Pipeline and Storage segment s capital expenditures for 2009 and 2008 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 and $149.2 million for the years ended September 30, 2009 and 2008, respectively.

Exploration and Production

In 2010, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $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, $27.6 million for the West Coast region and $355.7 million for the Appalachian region (including $332.4 million in the Marcellus Shale area). These amounts included approximately $28.9 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian region include 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, and will help the Company continue its developmental drilling program. The transaction closed on March 12, 2010. The Company funded this transaction with cash from operations.

In 2009, the Exploration and Production segment s capital expenditures were primarily well drilling and completion expenditures and included approximately $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, $31.4 million for the West Coast region and $138.6 million for the Appalachian region. 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 $39.2 million in cash (including cash acquired of $4.3 million). The cash acquired at acquisition includes $2.0 million held in escrow at September 30, 2010 and 2009. Seneca placed this amount in escrow as part of the purchase price. Currently, the Company and Ivanhoe Energy are negotiating a final resolution to the issue of whether Ivanhoe Energy is entitled to some or all of the amount held in escrow. This purchase complements the segment s existing oil producing assets in the Midway Sunset Field in California. This acquisition was funded with cash on hand.

In 2008, the Exploration and Production segment s capital expenditures were primarily well drilling and completion expenditures and included approximately $63.6 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, $62.8 million for the West Coast region and $65.8 million for the Appalachian region. These amounts included approximately $25.4 million spent to develop proved undeveloped reserves. The Appalachian region capital expenditures include $2.4 million for the purchase of storage facilities, buildings, and base gas from Supply Corporation, as shown in the table above.

All Other and Corporate

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, as discussed below.

NFG Midstream Covington, LLC, a wholly owned subsidiary of Midstream Corporation, constructed a gathering system in Tioga County, Pennsylvania. The project, called the Covington Gathering System, was constructed in two phases. The first phase was completed and placed in service in November 2009. The second phase was placed in service in May 2010. The system consists of approximately 10 miles of gathering system at a cost of $14.5 million. During the years ended September 30, 2010 and 2009, Midstream Corporation spent $6.4 million and $8.1 million, respectively, 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. In addition to the 23 million board feet mentioned above, the Company expects to sell an additional 17 million board feet of logs to the purchaser over a five-year period, during which time the Company anticipates receiving up to an additional $10 million in proceeds. There was not a material impact to earnings from this sale.

In 2008, the majority of the All Other and Corporate category s expenditures for long-lived assets were for construction of a lumber sorter for Highland s sawmill operations that was placed into service in October 2007, as well as for purchases of equipment for Highland s sawmill and kiln operations. Additionally, Horizon Power sold a gas-powered turbine in March 2008 that it had planned to use in the development of a co-generation plant. Horizon Power received proceeds of $5.3 million and recorded a pre-tax gain of $0.9 million associated with the sale.

Estimated Capital Expenditures

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

	Year Ended September 30		
	2011	**2012**	**2013**
		(Millions)	
Utility	$ 58.0	$ 58.0	$ 58.0
Pipeline and Storage	130.0	124.0	341.0
Exploration and Production(1)(2)	455.0	596.0	606.0
All Other	30.0	11.0	10.0

$ 673.0	$ 789.0	$ 1,015.0

(1) Includes estimated expenditures for the years ended September 30, 2011, 2012 and 2013 of approximately $140 million, $74 million and $29 million, respectively, to develop proved undeveloped reserves. The Company is committed to developing its proved undeveloped reserves within five years of being recorded as proved undeveloped reserves as required by the SEC s final rule on Modernization of Oil and Gas Reporting.

(2) Exploration and Production segment estimated capital expenditures do not take into account possible joint-venture opportunities involving this segment s Marcellus Shale acreage. The amounts could change if a joint-venture is formed.

Utility

Estimated capital expenditures for the Utility segment in 2011 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 2011 will be concentrated on the replacement of transmission and storage lines, the reconditioning of storage wells, improvements of compressor stations and construction of new pipeline and compressor stations to support expansion projects.

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, amounts remain in Deferred Charges until construction begins, at which 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, 2010, the total amount reserved for the Pipeline and Storage segment s preliminary survey and investigation costs was $5.1 million.

Supply Corporation is moving forward with several projects designed to move anticipated Marcellus production gas to other interstate pipelines and to markets beyond Supply Corporation s pipeline system.

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 will enter into a 20-year firm transportation agreement for 320,000 Dth/day. This capacity will provide the subscribing shipper with a firm transportation path from the Tennessee Gas Pipeline (TGP) 300 Line at Ellisburg into 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. Service is expected to begin in late 2012, and Supply Corporation has begun working on an application for FERC authorization of the project, which it expects to file in the second quarter of fiscal year 2011. The project facilities involve additional compression at Supply Corporation s existing Ellisburg Station and at a new station in East Aurora, New York, along with other system enhancements including the jointly owned Niagara Spur Loop Line. The preliminary cost estimate for the Northern Access expansion is $60 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2010, less than $0.1 million has been spent to study the Northern Access expansion project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2010.

One strategic horsepower 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. A precedent agreement for 150,000 Dth/day of firm transportation has been executed and negotiations are underway for the remaining capacity. The project will allow Marcellus production located in the vicinity of Line N to flow south into Texas Eastern and access markets off Texas Eastern s system, with a projected in-service date of September 2011. On October 20, 2009, the FERC granted Supply Corporation s request for a pre-filing environmental review of the Line N Expansion Project, and on June 11, 2010, Supply Corporation filed an NGA Section 7(c) application to the FERC for approval of the project. The preliminary cost estimate for the Line N Expansion Project is $23 million, all of which is expected to be spent in fiscal 2011 and 2012 except for approximately $2.0 million already spent through September 30, 2010. 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, all previous reserves established in connection with this project have been reversed, and the $2.0 million has been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

Supply Corporation has also executed a precedent agreement for 150,000 Dth/day of additional capacity on Line N to TETCO Holbrook to be ready for service beginning November 2012 (Line N Phase II Expansion Project). The Line N Phase II Expansion Project will provide approximately 195,000 Dth/day of incremental firm transportation capacity. Marketing efforts are underway for the remaining 45,000 Dth/day of capacity. The preliminary cost estimate for the Line N Phase II Expansion Project is approximately $40 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2010, less than $0.1 million has been spent to study the Line N Phase II Expansion Project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2010.

Another strategic horsepower expansion project, involving the addition of compression at Supply Corporation s existing interconnect with TGP at Lamont, Pennsylvania, has been in service since June 15, 2010 (Lamont Project).

A second Lamont Project phase is planned (Lamont Phase II Project). With the construction of additional horsepower, 50,000 Dth/day of incremental firm capacity will be available starting July 1, 2011 ramping up to full service by October 1, 2011. Supply Corporation has two signed precedent agreements for the full capacity of this project. The preliminary cost estimate for the Lamont Phase II Project is approximately $7 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2010, less than $0.1 million has been spent to study the Lamont Phase II project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2010.

In addition, Supply Corporation continues to actively pursue its largest planned expansion, the West-to-East (W2E) pipeline project, which is designed to transport Rockies and/or locally produced 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 first two 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 2013.

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 $260 million, approximately $191 million of which is expected to be spent during the period of fiscal 2011 through 2013. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2010, approximately $3.8 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, 2010.

Supply Corporation expects that its previously announced Appalachian Lateral project will complement the W2E Overbeck to Leidy project due to its strategic upstream location. The Appalachian Lateral pipeline, which would be routed through several counties in central Pennsylvania where producers are actively drilling and seeking market access for their newly discovered reserves, will be able to collect and transport locally produced Marcellus shale gas into the W2E Overbeck to Leidy facilities. Supply Corporation expects to continue marketing efforts for the Appalachian Lateral and all other remaining sections of W2E. The timeline and projected costs associated with W2E sections other than W2E Overbeck to Leidy, including the Appalachian Lateral project, will depend on market development, and as of September 30, 2010, no preliminary survey and investigation charges had been spent on those projects and no capital expenditures are included as estimated capital expenditures in the table above.

Supply Corporation has also developed plans for new storage capacity by expansion of two of its existing storage facilities. The expansion of the East Branch and Galbraith fields will provide 7.9 MMDth of incremental storage capacity and approximately 88 MDth per day of additional withdrawal deliverability. This storage expansion project, if pursued, would require an NGA Section 7(c) application, which Supply Corporation has not yet filed. The preliminary cost estimate for this storage expansion project is $64 million. These expenditures are not included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2010, approximately $1.0 million has been spent to study this storage expansion project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2010. The specific timeline associated with the storage expansion will depend on market development, which at this time, due to economic conditions, does not warrant additional project development.

Empire has executed precedent 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 16-mile extension of its recently completed Empire Connector line, in Tioga County, Pennsylvania. Empire s preliminary cost estimate for the Tioga County Extension Project is approximately $46 million, all of which is expected to be spent in fiscal 2011 and 2012 except for approximately $2.0 million already spent through September 30, 2010. These expenditures are 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 January 28, 2010, the FERC granted Empire s request for a pre-filing environmental review of the Tioga County Extension Project, and on August 26, 2010, Empire filed an NGA Section 7(c) application to the FERC for approval of the project. Empire anticipates that these facilities will be placed in service on September 1, 2011. The Company has determined that it is highly probable that this project will be built. Accordingly, all previous reserves have been reversed and the $2.0 million has been reestablished as a Deferred Charge on the Consolidated Balance Sheet. Empire is evaluating a second phase expansion of the Tioga County Extension Project that could extend the Empire system further into the Marcellus production area in Pennsylvania, and/or increase the capacity by up to 260,000 Dth/day by late 2013. The cost of this second phase could be as much as $135 million, most of which would be spent in fiscal 2013 and is included as Pipeline and Storage segment estimated capital expenditures in the table above.

The Company anticipates financing the Line N Expansion Projects, the Lamont Projects, the Northern Access expansion project, the W2E Overbeck to Leidy project, the Appalachian Lateral project, and the Tioga County Extension Projects, all of which are discussed above, with a combination of cash from operations, short-term debt, and long-term debt. The Company had $395.2 million in Cash and Temporary Cash Investments at September 30, 2010, as shown on the Company s Consolidated Balance Sheet. The Company expects to use cash from operations as the first means of financing these projects, with short-term debt providing temporary financing when needed. The Company may issue some long-term debt in conjunction with these projects in the later part of fiscal 2011 or in fiscal 2012.

Exploration and Production

Estimated capital expenditures in 2011 for the Exploration and Production segment include approximately $11.0 million for the Gulf Coast region, substantially all of which is for the off-shore program in the shallow waters of the Gulf of Mexico, $39.0 million for the West Coast region and $405.0 million for the Appalachian region. The Company anticipates drilling 100 to 130 gross wells in the Marcellus Shale during 2011.

Estimated capital expenditures in 2012 for the Exploration and Production segment include approximately $20.0 million for the Gulf Coast region, substantially all of which is for the off-shore program in the shallow waters of the Gulf of Mexico, $43.0 million for the West Coast region and $533.0 million for the Appalachian region. The Company anticipates drilling 130 to 160 gross wells in the Marcellus Shale during 2012.

Estimated capital expenditures in 2013 for the Exploration and Production segment include approximately $47.0 million for the West Coast region and $559.0 million for the Appalachian region. The Company does not expect to incur any significant capital expenditures in the Gulf Coast region during 2013. The Company anticipates drilling 140 to 170 gross wells in the Marcellus Shale during 2013.

It is anticipated that these future capital expenditures will be funded with a combination of cash from operations, short-term debt, 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. The Company expects to use cash from operations as the first means of financing these expenditures, with short-term debt providing temporary financing when needed. The Company may issue some long-term debt in conjunction with these expenditures in the later part of fiscal 2011 or in fiscal 2012.

All Other and Corporate

Estimated capital expenditures in 2011 for the All Other and Corporate category will primarily be for construction of anticipated gathering systems, including the construction of Midstream Corporation s Trout Run Gathering System, as discussed below.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, is planning a gathering system in Lycoming County, Pennsylvania. The project, called the Trout Run Gathering System, is anticipated to be placed in service in the fall of 2011. The system will consist of approximately 15.5 miles of gathering system at a cost of $27 million. These expenditures are included as All Other category capital expenditures in the table above. As of September 30, 2010, the Company has spent approximately $0.1 million in costs related to this project.

The Company anticipates funding the Midstream Corporation project with cash from operations and/or short-term borrowings. Given the Company s cash position at September 30, 2010, the Company expects to use cash from operations as the first means of financing these projects.

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

The Company did not have any outstanding short-term notes payable to banks or commercial paper at September 30, 2010 or during the fiscal year ended September 30, 2010. However, 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. 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 $405.0 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, 2010, the Company s debt to capitalization ratio (as calculated under the facility) was .42. The constraints specified in the committed credit facility would permit an additional $1.99 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. In addition, the Company s cost of capital is directly affected by its credit ratings. At September 30, 2010, the Company s long-term debt ratings were: BBB (S&P), Baa1 (Moody s Investor Service), and BBB+ (Fitch Ratings Service). In March 2010, Fitch Ratings Service decreased the Company s long-term debt rating from A- to BBB+. The Company does not believe that this ratings action will impact its access to the commercial paper markets. At September 30, 2010, the Company s commercial paper ratings were: A-2 (S&P), P-2 (Moody s Investor Service), and F2 (Fitch Ratings Service). A credit rating is not a recommendation to buy, sell or hold securities. Each credit rating agency has its own methodology for assigning ratings, and, accordingly, each rating should be considered in the context of the applicable methodology, independently of all other ratings. The rating agencies provide ratings at the request of the Company and charge the Company fees for their services.

Under the Company s existing indenture covenants, at September 30, 2010, the Company would have been permitted to issue up to a maximum of $1.3 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 7.9%) of the Company s long-term debt (as of September 30, 2010) 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, 2010, the Company had no debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 6.95% at both September 30, 2010 and September 30, 2009. If the Company were to issue long-term debt today, its borrowing costs might be expected to be in the range of 5.0% to 6.5% depending on the maturity date. Refer to Interest Rate Risk in this Item for a more detailed breakdown of the Company s embedded cost of long-term debt.

Current Portion of Long-Term Debt at September 30, 2010 consists of $200 million of 7.50% medium-term notes that mature in November 2010. Currently, the Company expects to refund these medium-term notes in November 2010 with cash on hand and/or short-term borrowings.

In April 2009, the Company issued $250.0 million of 8.75% notes due in May 2019. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $247.8 million. These notes were registered under the Securities Act of 1933. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including to replenish cash that was used to pay the $100 million due at the maturity of the Company s 6.0% medium-term notes on March 1, 2009.

On December 8, 2005, the Company s Board of Directors authorized the Company to implement a share repurchase program, whereby the Company could repurchase outstanding shares of common stock, up to an aggregate amount of eight million shares in the open market or through privately negotiated transactions. The Company completed the repurchase of the eight million shares during 2008 for a total program cost of $324.2 million (of which 4,165,122 shares were repurchased during the year ended September 30, 2008 for $191.0 million). In September 2008, the Company s Board of Directors authorized the repurchase of an additional eight million shares of the Company s common stock. Under this new authorization, the Company repurchased 1,028,981 shares for $46.0 million through September 17, 2008. The Company, however, stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. 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. The share repurchases mentioned above were funded with cash provided by operating activities and/or through the use of the Company s lines of credit.

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 $27.4 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, 2010, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2011	2012	2013	2014	2015	Thereafter	Total
	(Millions)						

Long-Term Debt, including interest expense(1)	$ 274.0	$ 213.2	$ 304.2	$ 48.7	$ 48.7	$ 839.9	$ 1,728.7
Operating Lease Obligations	$ 5.1	$ 4.6	$ 3.5	$ 3.2	$ 2.8	$ 8.2	$ 27.4
Purchase Obligations:							
Gas Purchase Contracts(2)	$ 337.8	$ 47.7	$ 13.2	$ 0.4	$	$	$ 399.1
Transportation and Storage Contracts	$ 42.3	$ 38.6	$ 38.4	$ 34.3	$ 19.8	$ 14.5	$ 187.9
Other	$ 25.1	$ 5.1	$ 4.0	$ 3.9	$ 3.7	$ 11.3	$ 53.1

(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 2010, the Company contributed $22.2 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2011 will be in the range of $40.0 million to $45.0 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 2011 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 2010, the Company contributed $25.5 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 2011 will be in the range of $25.0 million to $30.0 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, 2010, the Company has a federal net operating loss carryover of $19.7 million, which expires in varying amounts between 2023 and 2029. Although this loss carryover is subject to certain annual limitations, no valuation allowance was recorded because of management s determination that the amount 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, 2010 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 Wall Street Reform and Consumer Protection Act (H.R. 4173) was signed into law. The law includes provisions related to the swaps and over-the-counter derivatives markets. A variety of rules must be adopted by federal agencies (including the Commodity Futures Trading Commission, SEC and the FERC) to implement the law. These rules, which will be implemented over time frames as determined in the law, could have a significant impact on the Company that was not clearly defined in the law itself. Under the law, the Company expects to be exempt from mandatory clearing and exchange trading requirements for most or all of its commodity hedges. Capital and margin requirements for these hedges are expected to be determined as regulators write more detailed rules and requirements. While the Company is currently reviewing the provisions of H.R. 4173, it will not be able to determine the impact to its financial condition until the final rules are issued.

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 $16.5 million at September 30, 2010 and represent 4.6% of the Total Net Assets shown in Item 8 at Note F Fair Value Measurements at September 30, 2010.

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 decrease in the net fair value of the Level 3 positions from a net asset position at October 1, 2009 to a net liability position at September 30, 2010, as shown in Item 8 at Note F, was attributable to an increase 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, 2010.

The fair value of all of the Company s Net Derivative Assets was reduced by $0.7 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.

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, 2010. At September 30, 2010, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2014.

Natural Gas Price Swap Agreements

	Expected Maturity Dates				
	2011	**2012**	**2013**	**2014**	**Total**
Notional Quantities (Equivalent Bcf)	20.4	13.9	3.9	0.1	38.3
Weighted Average Fixed Rate (per Mcf)	$ 6.77	$ 7.11	$ 6.67	$ 7.12	$ 6.88
Weighted Average Variable Rate (per Mcf)	$ 4.67	$ 5.47	$ 5.85	$ 5.78	$ 5.09

Of the total Bcf above, 0.4 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $7.18 per Mcf. The remaining 37.9 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $6.88 per Mcf.

Crude Oil Price Swap Agreements

	Expected Maturity Dates			
	2011	**2012**	**2013**	**Total**
Notional Quantities (Equivalent bbls)	1,560,000	972,000	156,000	2,688,000
Weighted Average Fixed Rate (per bbl)	$ 69.93	$ 69.34	$ 72.98	$ 69.89
Weighted Average Variable Rate (per bbl)	$ 74.71	$ 78.04	$ 79.27	$ 76.18

At September 30, 2010, the Company would have received from its respective counterparties an aggregate of approximately $67.3 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 $16.5 million to terminate the crude oil price swap agreements outstanding at September 30, 2010.

At September 30, 2009, the Company had natural gas price swap agreements covering 38.0 Bcf at a weighted average fixed rate of $7.15 per Mcf. The Company also had crude oil price swap agreements covering 2,688,000 bbls at a weighted average fixed rate of $71.14 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, 2010, the Company held no futures contracts with maturity dates extending beyond 2013.

Futures Contracts

	Expected Maturity Dates			
	2011	**2012**	**2013**	**Total**
Net Contract Volume Purchased (Sold) (Equivalent Bcf)	4.8	2.8	0.1(1)	7.7
Weighted Average Contract Price (per Mcf)	$ 5.42	$ 5.85	$ 6.39	$ 5.48
Weighted Average Settlement Price (per Mcf)	$ 5.64	$ 6.45	$ 7.15	$ 5.77

(1) The Energy Marketing segment has purchased 14 futures contracts (1 contract = 10,000 Dth) for 2013.

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. Of this amount, 14.1 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 0.1 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 $13.2 million to terminate these futures contracts at September 30, 2010.

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. Of this amount, 5.7 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 $7.4 million to terminate these futures contracts at September 30, 2010.

At September 30, 2009, the Company had long (purchased) futures contracts covering 11.6 Bcf of gas extending through 2012 at a weighted average contract price of $6.37 per Mcf and a weighted average settlement price of $6.07 per Mcf.

At September 30, 2009, the Company had short (sold) futures contracts covering 6.7 Bcf of gas extending through 2011 at a weighted average contract price of $7.37 per Mcf and a weighted average settlement price of $6.07 per Mcf. Of this amount, 5.8 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 0.9 Bcf is accounted for as fair value hedges used to hedge against falling prices.

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 of the eleven counterparties are in a net gain position. On average, the Company had $6.5 million of credit exposure per counterparty in a gain position at September 30, 2010. The maximum credit exposure per counterparty at September 30, 2010 was $11.9 million. BP Energy Company (an affiliate of BP Corporation North America, Inc.) was one of the ten counterparties in a gain position. At September 30, 2010, the Company had an $11.3 million receivable with BP Energy Company. The Company considered the credit quality of BP Energy Company (as it does with all of its counterparties) in determining hedge effectiveness and believes the hedges remain effective. The Company had not received any collateral from these counterparties at September 30, 2010 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.

As of September 30, 2010, nine 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 (the lower of the S&P or Moody s Debt Rating), 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 and the Company s credit rating declined, then additional hedging collateral deposits would be required. At September 30, 2010, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $42.1 million according to the Company s internal model (discussed in Item 8 at Note F Fair Value Measurements). At September 30, 2010, the fair market value of the derivative financial instrument liability with a credit-risk related contingency feature was $14.3 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 $1.0 million in hedging collateral deposits at September 30, 2010. This is discussed in Item 8 at Note A under Hedging Collateral Deposits.

For its exchange traded futures contracts which are in a liability position, the Company had posted $10.1 million in hedging collateral as of September 30, 2010. 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						
	2011	**2012**	**2013**	**2014**	**2015**	**Thereafter**	**Total**
			(Dollars in millions)				
Long-Term Fixed Rate Debt	$ 200.0	$ 150.0	$ 250.0	$	$	$ 649.0	$ 1,249.0
Weighted Average Interest Rate Paid	7.5%	6.7%	5.3%			7.5%	7.0%
Fair Value of Long-Term Fixed Rate Debt = $1,423.3							

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 that portions of the rate order were invalid because they failed to meet the applicable legal standard for agency decisions. Among the issues challenged by the Company was the reasonableness of the NYPSC s disallowance of expense items and the methodology used for calculating rate of return, which the appeal contended understated the Company s cost of equity. Because of the issues appealed, the case was later transferred to the Appellate Division, New York State s second-highest court. On December 31, 2009, the Appellate Division issued its Opinion and Judgment. The court upheld the NYPSC s determination relating to the authorized rate of return but also supported the Company s argument that the NYPSC improperly disallowed recovery of certain environmental clean-up costs. On February 1, 2010, the NYPSC filed a motion with the Court of Appeals, New York State s highest court, seeking permission to appeal the Appellate Division s annulment of that part of the rate order relating to disallowance of environmental clean up costs. On May 4, 2010, the NYPSC s motion was granted, and the matter will be heard by the Court of Appeals. The Briefing schedule began on July 28, 2010 and is followed by oral argument. The Company cannot predict the outcome of the appeal proceedings at this time.

Pennsylvania Jurisdiction

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

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. The rate settlement approved by the FERC on February 9, 2007 requires Supply Corporation to make a general rate filing to be effective December 1, 2011, and bars Supply Corporation from making a general rate filing before then, with some exceptions specified in the settlement.

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, 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, 2010, 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 $17.3 million to $21.5 million. The minimum estimated liability of $17.3 million has been recorded on the Consolidated Balance Sheet at September 30, 2010. 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. The EPA has determined that stationary sources of significant greenhouse gas emissions will be required under the federal Clean Air Act to obtain permits covering such emissions beginning in January 2011. In addition, the U.S. Congress has been considering 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. 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. 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 September 2006, the FASB issued authoritative guidance for using fair value to measure assets and liabilities. This guidance serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. This guidance is to be applied whenever assets or liabilities are to be measured at fair value. On October 1, 2008, the Company adopted this guidance for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. The FASB s authoritative guidance for using fair value to measure nonfinancial assets and nonfinancial liabilities on a nonrecurring basis became effective during the quarter ended December 31, 2009. The Company s nonfinancial assets and nonfinancial liabilities were not significantly impacted by this guidance during the year ended September 30, 2010. The Company had identified Goodwill as being the major nonfinancial asset that may have been impacted by the adoption of this guidance; however, the adoption of the guidance did not have a significant impact on the Company s annual test for goodwill impairment. The Company had identified Asset Retirement Obligations as a nonfinancial liability that may have been impacted by the adoption of the guidance. The adoption of the guidance did not have a significant impact on the Company s Asset Retirement Obligations. Refer to Item 8 at Note B Asset Retirement Obligations for further disclosure. Additionally, in February 2010, the FASB issued updated guidance that includes additional requirements and disclosures regarding fair value measurements. The guidance now requires the gross presentation of activity within the Level 3 roll forward and requires disclosure of details on transfers in and out of Level 1 and 2 fair value measurements. It also provides further clarification on the level of disaggregation of fair value measurements and disclosures on inputs and valuation techniques. The Company has updated its disclosures to reflect the new requirements in Item 8 at Note F Fair Value Measurements, except for the Level 3 roll forward gross presentation, which will be effective as of the Company s first quarter of fiscal 2012.

On December 31, 2008, the SEC issued a final rule on Modernization of Oil and Gas Reporting. The final rule modifies the SEC s reporting and disclosure rules for oil and gas reserves and aligns the full cost accounting rules with the revised disclosures. The most notable changes of the final rule include 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 final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. Additionally, on January 6, 2010, the FASB amended the oil and gas accounting standards to conform to the SEC final rule on Modernization of Oil and Gas Reporting (final rule). The revised reporting and disclosure requirements became effective with this Form 10-K for the period ended September 30, 2010. The Company has updated its disclosures to reflect the new requirements in Item 8 at Note Q Supplementary Information for Oil and Gas Producing Activities. The Company chose not to disclose probable and possible reserves. In order to estimate the effect of adopting the final rule, the Company would be required to prepare two sets of reserve reports (applying both the final rule and previous rules). There would be significant time and expense associated with preparing two sets of reports to address changes between the different rules. Since the information obtained from the dual reserve reports would be relevant only for transitional purposes, the cost is deemed to exceed the benefit. As a result, the Company has determined it would be impractical to estimate the impact of adoption of the final rule.

In March 2009, the FASB issued authoritative guidance that expands the disclosures required in an employer s financial statements about pension and other post-retirement benefit plan assets. The additional disclosures include more details on how investment allocation decisions are made, the plan s investment policies and strategies, the major categories of plan assets, the inputs and valuation techniques used to measure the fair value of plan assets, the effect of fair value measurements using significant unobservable inputs on changes in plan assets for the period, and disclosure regarding significant concentrations of risk within plan assets. The additional disclosure requirements became effective with this Form 10-K for the period ended September 30, 2010. The Company has updated its disclosures to reflect the new requirements in Item 8 at Note H Retirement Plan and Other Post-Retirement Benefits.

In June 2009, the FASB issued amended authoritative guidance to improve and clarify financial reporting requirements by companies involved with variable interest entities. The new guidance requires a company to perform an analysis to determine whether the company s variable interest or interests give it a controlling financial interest in a variable interest entity. The analysis also assists in identifying the primary beneficiary of a variable interest entity. This authoritative guidance will be effective as of the Company s first quarter of fiscal 2011. Given the current organizational structure of the Company, the Company does not believe this authoritative guidance will have any impact on its consolidated financial statements.

EFFECTS OF INFLATION

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

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, 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, seek similar expressions, are forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management s examination of historical operating trends, data contained in the Company s records and other data available from third parties, 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. 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;

2. 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;

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

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

5. 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, 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;

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

7. Uncertainty of oil and gas reserve estimates;

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

9. Significant changes in market dynamics or competitive factors affecting the Company s ability to retain existing customers or obtain new customers;

10. Changes in demographic patterns and weather conditions;

11. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment of derivative financial instruments;

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

13. Changes in the availability and/or cost of derivative financial instruments;

14. Changes in the price differentials between oil having different quality and/or different geographic locations, or changes in the price differentials between natural gas having different heating values and/or different geographic locations;

15. Changes in the projected profitability of pending or potential projects, investments or transactions;

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

17. Delays or changes in costs or plans with respect to our 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;

18. Governmental/regulatory actions, initiatives and proceedings, including those involving derivatives, acquisitions, financings, rate cases (which address, among other things, allowed rates of return, rate design and

retained natural gas), affiliate relationships, industry structure, franchise renewal, and environmental/safety requirements;

19. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;

20. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;

21. 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;

22. Significant changes in tax rates or policies or in rates of inflation or interest;

23. Significant changes in the Company s relationship with its employees or contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur;

24. Changes in accounting principles or the application of such principles to the Company;

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

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

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

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

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.

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 O Quarterly Financial Data (unaudited) and Note Q 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2010 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, 2010, 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.

As discussed in Note A to the consolidated financial statements, the Company changed the manner in which its oil and gas reserves are estimated, as well as the manner in which prices are determined to calculate the ceiling on capitalized oil and gas costs as of September 30, 2010.

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 24, 2010

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2010	**2009**	**2008**
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$ 1,760,503	$ 2,051,543	$ 2,396,837
Operating Expenses			
Purchased Gas	658,432	997,216	1,238,405
Operation and Maintenance	394,569	401,200	429,394
Property, Franchise and Other Taxes	75,852	72,102	75,525
Depreciation, Depletion and Amortization	191,199	170,620	169,846
Impairment of Oil and Gas Producing Properties		182,811	
	1,320,052	1,823,949	1,913,170
Operating Income	440,451	227,594	483,667
Other Income (Expense):			
Income from Unconsolidated Subsidiaries	2,488	3,366	6,303
Impairment of Investment in Partnership		(1,804)	
Other Income	3,638	8,200	7,164
Interest Income	3,729	5,776	10,815
Interest Expense on Long-Term Debt	(87,190)	(79,419)	(70,099)
Other Interest Expense	(6,756)	(7,370)	(3,271)
Income from Continuing Operations Before Income Taxes	356,360	156,343	434,579
Income Tax Expense	137,227	52,859	167,672
Income from Continuing Operations	219,133	103,484	266,907
Discontinued Operations:			
Income (Loss) from Operations, Net of Tax	470	(2,776)	1,821
Gain on Disposal, Net of Tax	6,310		
Income (Loss) from Discontinued Operations, Net of Tax	6,780	(2,776)	1,821
Net Income Available for Common Stock	225,913	100,708	268,728
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	948,293	953,799	983,776
	1,174,206	1,054,507	1,252,504
Share Repurchases			(194,776)

Cumulative Effect of Adoption of Authoritative Guidance for Income Taxes			(406)
Adoption of Authoritative Guidance for Defined Benefit Pension and Other Post-Retirement Plans		(804)	
Dividends on Common Stock	(110,944)	(105,410)	(103,523)
Balance at End of Year	$ 1,063,262	$ 948,293	$ 953,799
Earnings Per Common Share:			
Basic:			
Income from Continuing Operations	$ 2.70	$ 1.29	$ 3.25
Income (Loss) from Discontinued Operations	0.08	(0.03)	0.02
Net Income Available for Common Stock	$ 2.78	$ 1.26	$ 3.27
Diluted:			
Income from Continuing Operations	$ 2.65	$ 1.28	$ 3.16
Income (Loss) from Discontinued Operations	0.08	(0.03)	0.02
Net Income Available for Common Stock	$ 2.73	$ 1.25	$ 3.18
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	81,380,434	79,649,965	82,304,335
Used in Diluted Calculation	82,660,598	80,628,685	84,474,839

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2010	2009
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$ 5,637,498	$ 5,184,844
Less Accumulated Depreciation, Depletion and Amortization	2,187,269	2,051,482
	3,450,229	3,133,362
Current Assets		
Cash and Temporary Cash Investments	395,171	408,053
Cash Held in Escrow	2,000	2,000
Hedging Collateral Deposits	11,134	848
Receivables Net of Allowance for Uncollectible Accounts of $30,961 and $38,334, Respectively	132,136	144,466
Unbilled Utility Revenue	20,920	18,884
Gas Stored Underground	48,584	55,862
Materials and Supplies at average cost	24,987	24,520
Other Current Assets	115,969	68,474
Deferred Income Taxes	24,476	53,863
	775,377	776,970
Other Assets		
Recoverable Future Taxes	149,712	138,435
Unamortized Debt Expense	12,550	14,815
Other Regulatory Assets	542,801	530,913
Deferred Charges	9,646	2,737
Other Investments	77,839	78,503
Investments in Unconsolidated Subsidiaries	14,828	14,940
Goodwill	5,476	5,476
Intangible Assets	1,677	21,536
Fair Value of Derivative Financial Instruments	65,184	44,817
Other	306	6,625
	880,019	858,797
Total Assets	$ 5,105,625	$ 4,769,129

CAPITALIZATION AND LIABILITIES

Capitalization:

Comprehensive Shareholders Equity		
Common Stock, $1 Par Value		
Authorized 200,000,000 Shares; Issued and Outstanding 82,075,470 Shares and 80,499,915 Shares, Respectively	$ 82,075	$ 80,500
Paid In Capital	645,619	602,839
Earnings Reinvested in the Business	1,063,262	948,293
Total Common Shareholders Equity Before Items Of Other Comprehensive Loss	1,790,956	1,631,632
Accumulated Other Comprehensive Loss	(44,985)	(42,396)
Total Comprehensive Shareholders Equity	1,745,971	1,589,236
Long-Term Debt, Net of Current Portion	1,049,000	1,249,000
Total Capitalization	2,794,971	2,838,236
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper		
Current Portion of Long-Term Debt	200,000	
Accounts Payable	145,223	90,723
Amounts Payable to Customers	38,109	105,778
Dividends Payable	28,316	26,967
Interest Payable on Long-Term Debt	30,512	32,031
Customer Advances	27,638	24,555
Customer Security Deposits	18,320	17,430
Other Accruals and Current Liabilities	16,046	18,875
Fair Value of Derivative Financial Instruments	20,160	2,148
	524,324	318,507
Deferred Credits		
Deferred Income Taxes	800,758	663,876
Taxes Refundable to Customers	69,585	67,046
Unamortized Investment Tax Credit	3,288	3,989
Cost of Removal Regulatory Liability	124,032	105,546
Other Regulatory Liabilities	89,334	120,229
Pension and Other Post-Retirement Liabilities	446,082	415,888
Asset Retirement Obligations	101,618	91,373
Other Deferred Credits	151,633	144,439
	1,786,330	1,612,386
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 5,105,625	$ 4,769,129

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2010	2009	2008
	(Thousands of dollars)		
Operating Activities			
Net Income Available for Common Stock	$ 225,913	$ 100,708	$ 268,728
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Gain on Sale of Discontinued Operations	(10,334)		
Impairment of Oil and Gas Producing Properties		182,811	
Depreciation, Depletion and Amortization	191,809	173,410	170,623
Deferred Income Taxes	134,679	(2,521)	72,496
Income from Unconsolidated Subsidiaries, Net of Cash Distributions	112	(466)	1,977
Impairment of Investment in Partnership		1,804	
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(13,207)	(5,927)	(16,275)
Other	9,108	19,829	4,858
Change in:			
Hedging Collateral Deposits	(10,286)	(847)	4,065
Receivables and Unbilled Utility Revenue	10,262	47,658	(16,815)
Gas Stored Underground and Materials and Supplies	6,546	43,598	(22,116)
Unrecovered Purchased Gas Costs		37,708	(22,939)
Prepayments and Other Current Assets	(34,288)	2,921	(36,376)
Accounts Payable	8,047	(61,149)	32,763
Amounts Payable to Customers	(67,669)	103,025	(7,656)
Customer Advances	3,083	(8,462)	10,154
Customer Security Deposits	890	3,383	609
Other Accruals and Current Liabilities	(3,649)	13,676	(4,250)
Other Assets	7,237	(35,140)	(11,887)
Other Liabilities	1,442	(4,201)	54,817
Net Cash Provided by Operating Activities	459,695	611,818	482,776
Investing Activities			
Capital Expenditures	(455,764)	(313,633)	(397,734)
Investment in Subsidiary, Net of Cash Acquired		(34,933)	
Net Proceeds from Sale of Timber Mill and Related Assets	15,770		
Net Proceeds from Sale of Landfill Gas Pipeline Assets	38,000		
Cash Held in Escrow		(2,000)	58,397
Net Proceeds from Sale of Oil and Gas Producing Properties		3,643	5,969
Other	(251)	(2,806)	4,376
Net Cash Used in Investing Activities	(402,245)	(349,729)	(328,992)

Financing Activities			
Excess Tax Benefits Associated with Stock-Based Compensation Awards	13,207	5,927	16,275
Shares Repurchased under Repurchase Plan			(237,006)
Net Proceeds from Issuance of Long-Term Debt		247,780	296,655
Reduction of Long-Term Debt		(100,000)	(200,024)
Net Proceeds from Issuance of Common Stock	26,057	28,176	17,432
Dividends Paid on Common Stock	(109,596)	(104,158)	(103,683)
Net Cash Provided By (Used in) Financing Activities	(70,332)	77,725	(210,351)
Net Increase (Decrease) in Cash and Temporary Cash Investments	(12,882)	339,814	(56,567)
Cash and Temporary Cash Investments At Beginning of Year	408,053	68,239	124,806
Cash and Temporary Cash Investments At End of Year	$ 395,171	$ 408,053	$ 68,239
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 93,333	$ 75,640	$ 69,841
Income Taxes	$ 30,975	$ 40,638	$ 103,154

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2010	**2009**	**2008**
	(Thousands of dollars)		
Net Income Available for Common Stock	$ 225,913	$ 100,708	$ 268,728
Other Comprehensive Income (Loss), Before Tax:			
Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(30,155)	(71,771)	(13,584)
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	5,000	1,008	1,924
Foreign Currency Translation Adjustment	53	(33)	12
Unrealized Loss on Securities Available for Sale Arising During the Period	(2,195)	(6,118)	(4,856)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	65,366	119,210	(31,490)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(41,320)	(114,380)	64,645
Other Comprehensive Income (Loss), Before Tax	(3,251)	(72,084)	16,651
Income Tax Benefit Related to the Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(11,379)	(27,082)	(5,127)
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	1,887	380	726
Income Tax Benefit Related to Unrealized Loss on Securities Available for Sale Arising During the Period	(831)	(2,311)	(1,434)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	26,628	48,293	(13,228)
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gains) Losses on Derivative Financial Instruments In Net Income	(16,967)	(46,005)	26,548
Income Taxes Net	(662)	(26,725)	7,485
Other Comprehensive Income (Loss)	(2,589)	(45,359)	9,166
Comprehensive Income	$ 223,324	$ 55,349	$ 277,894

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 its majority owned entities. The equity method is used to account for minority owned entities. 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.

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.

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.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 bills its 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.

Prior to December 10, 2008, 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. On December 10, 2008, Empire became FERC regulated. As a result, Empire now bills its customers based on a straight fixed-variable rate design. Changes in throughput due to weather variations no longer have a significant impact on Empire s revenue.

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.

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.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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.

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. In accordance with the SEC final rule on Modernization of Oil and Gas Reporting, the natural gas and oil prices used to calculate the full cost ceiling (as of September 30, 2010) 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, 2010, 2009, and 2008, estimated future net cash flows were increased by $65.4 million, $143.3 million and $34.5 million, respectively. The Company s capitalized costs exceeded the full cost ceiling for the Company s oil and gas properties at December