NATIONAL FUEL GAS CO
Form 10-K
November 26, 2008

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**UNITED STATES SECURITIES AND EXCHANGE COMMISSION**
**Washington, D.C. 20549**
**Form 10-K**

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

**For the Fiscal Year Ended September 30, 2008**

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

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<br>(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 $3,768,755,000 as of March 31, 2008.

Common Stock, $1 Par Value, outstanding as of October 31, 2008: 79,124,644 shares.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant s definitive Proxy Statement for its 2009 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

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## Glossary of Terms

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

***National Fuel Gas Companies***

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

**Data-Track** Data-Track Account Services, Inc.

**Distribution Corporation** National Fuel Gas Distribution Corporation

**Empire** Empire State Pipeline

**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.

**Leidy Hub** Leidy Hub, Inc.

**Midstream** 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

**U.E.** United Energy, a.s.

***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***

**APB 18** Accounting Principles Board Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock

**APB 25** Accounting Principles Board Opinion No. 25, Accounting for Stock Issued to Employees

**ARB 51** Accounting Research Bulletin No. 51, Consolidated Financial Statements

**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. National Fuel 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.

**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 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.

**FIN** FASB Interpretation Number

**FIN 47** FASB Interpretation No. 47, Accounting for Conditional Asset Retirement Obligations an Interpretation of SFAS 143.

**FIN 48** FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an Interpretation of SFAS 109.

**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

**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)

**MMcf** Million cubic feet (of natural gas)

**MMcfe** Million cubic feet equivalent

**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

**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 these reserves productive.

**PRP** Potentially responsible party

**PUHCA 1935** Public Utility Holding Company Act of 1935

**PUHCA 2005** Public Utility Holding Company Act of 2005

**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 utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or unbundled ) 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.

**SAR** Stock-settled stock appreciation right

**SFAS** Statement of Financial Accounting Standards

**SFAS 5** Statement of Financial Accounting Standards No. 5, Accounting for Contingencies

**SFAS 69** Statement of Financial Accounting Standards No. 69, Disclosures about Oil and Gas Producing Activities

**SFAS 71** Statement of Financial Accounting Standards No. 71, Accounting for the Effects of Certain Types of Regulation

**SFAS 87** Statement of Financial Accounting Standards No. 87, Employers Accounting for Pensions

**SFAS 88** Statement of Financial Accounting Standards No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits

**SFAS 106** Statement of Financial Accounting Standards No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions.

**SFAS 109** Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes

**SFAS 112** Statement of Financial Accounting Standards No. 112, Employers Accounting for Postemployment Benefits, an amendment of SFAS 5 and 43

**SFAS 115** Statement of Financial Accounting Standards No. 115, Accounting for Certain Investments in Debt and Equity Securities

**SFAS 123** Statement of Financial Accounting Standards No. 123, Accounting for Stock-Based Compensation

**SFAS 123R** Statement of Financial Accounting Standards No. 123R, Share-Based Payment

**SFAS 132R** Statement of Financial Accounting Standards No. 132R, Employers Disclosures about Pensions and Other Postretirement Benefits

**SFAS 133** Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities

**SFAS 141R** Statement of Financial Accounting Standards No. 141R, Business Combinations

**SFAS 142** Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets

**SFAS 143** Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations

**SFAS 157** Statement of Financial Accounting Standards No. 157, Fair Value Measurements

**SFAS 158** Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of SFAS 87, 88, 106, and 132R

**SFAS 159** Statement of Financial Accounting Standards No. 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of SFAS 115

**SFAS 160** Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51

**SFAS 161** Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133

**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, 2008**

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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 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, projects, believes, seeks, will, and may a

## 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 five 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 727,000 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 State Pipeline (Empire), a New York joint venture between two wholly owned subsidiaries of the Company. 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 intrastate pipeline company acquired by the Company in 2003, 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, which is 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. Empire is constructing the Empire Connector project, which consists of a compressor station and a 77-mile pipeline extension from near Rochester, New York to an interconnection near Corning, New York with the unaffiliated Millennium Pipeline project, which is also under construction. The Millennium Pipeline is expected to serve the New York City area upon its completion. Upon completion of the Empire Connector and Millennium Pipeline projects, which is currently expected to occur in December 2008, the Company expects that Empire will become an interstate pipeline company and will merge into Empire Pipeline, Inc. as described below.

3. The Exploration and Production segment operations are carried out by Seneca Resources Corporation (Seneca), a Pennsylvania corporation. Seneca is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, in Wyoming, and in the Gulf Coast region of Texas, Louisiana, and Alabama, including offshore areas in federal

waters and some state waters. At September 30, 2008, the Company had U.S. reserves of 46,198 Mbbl of oil and 225,899 MMcf of natural gas.

In 2007, Seneca sold its subsidiary, Seneca Energy Canada Inc. (SECI), which conducted exploration and production operations in the provinces of Alberta, Saskatchewan and British Columbia in Canada.

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.

5. The Timber segment operations are carried out by Highland Forest Resources, Inc. (Highland), a New York corporation, and by a division of Seneca known as its Northeast Division. This segment markets timber from its New York and Pennsylvania land holdings, owns two sawmill operations in northwestern Pennsylvania and processes timber consisting primarily of high quality hardwoods. At September 30, 2008, the Company owned 103,680 acres of timber property and managed an additional 3,122 acres of timber rights.

Financial information about each of the Company s business segments can be found in Item 7, MD&A and also in Item 8 at Note J Business Segment Information.

The Company s other direct wholly owned subsidiaries are not included in any of the five reported business segments and consist of the following:

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 LFG, Inc. (Horizon LFG), a New York corporation engaged through subsidiaries in the purchase, sale and transportation of landfill gas in Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. Horizon LFG and one of its wholly owned subsidiaries own all of the partnership interests in Toro Partners, LP (Toro), a limited partnership which owns and operates short-distance landfill gas pipeline companies. The Company acquired Toro in June 2003;

Leidy Hub, Inc. (Leidy Hub), a New York corporation formed to provide various natural gas hub services to customers in the eastern United States;

Data-Track Account Services, Inc. (Data-Track), a New York corporation formed to provide collection services principally for the Company s subsidiaries;

Horizon Power, Inc. (Horizon Power), a New York corporation which is an exempt wholesale generator under PUHCA 2005 and is developing or operating mid-range independent power production facilities and landfill gas electric generation facilities;

Empire Pipeline, Inc., a New York corporation formed in 2005 to be the surviving corporation of a planned future merger with Empire, which is expected to occur after construction of the Empire Connector project (described below under the heading Rates and Regulation and under Item 7, MD&A under the headings Investing Cash Flow and Rate and Regulatory Matters ); and

National Fuel Gas 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 2008.

**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 C Regulatory Matters.

The Pipeline and Storage segment s rates, services and other matters are currently regulated by the FERC with respect to Supply Corporation and by the NYPSC with respect to Empire. The FERC has authorized Empire to construct and operate additional facilities (the Empire Connector project) and to become a FERC-regulated interstate pipeline company upon placement of those facilities into service, which is currently expected to occur in December 2008. 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 C Regulatory Matters. For further discussion of the Empire Connector project, refer to Item 7, MD&A under the headings Investing Cash Flow and Rate and 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 22.9% of the Company s 2008 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 20.1% of the Company s 2008 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 2009, 72.0% of Supply Corporation s total firm storage capacity was committed under contracts that, subject to 2008 shipper or Supply Corporation notifications, could have been terminated effective in 2009. Supply Corporation did not issue or receive any such storage contract termination notifications in 2008. The strong demand for market-area storage enabled Supply Corporation to eliminate its remaining storage service rate discounts in 2007, and effective April 1, 2008, all storage services were contracted at the maximum tariff rates.

Supply Corporation s firm transportation capacity is not limited to a fixed quantity, due to the diverse weblike 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 2,117 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,065 MDth per day or 50.3% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 102 MDth per day or 4.8% of contracted transportation capacity. The remaining 950 MDth or 44.9% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2009, 49.3% of Supply Corporation s contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2009 or, subject to 2008 shipper or Supply Corporation notifications, could have been terminated effective in 2009. Based on contract expirations and termination notices received in 2008 for 2009 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to decrease 0.3% in 2009. Similarly, 26.7% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2009 or, subject to 2008 shipper or Supply Corporation notifications, could have been terminated effective in 2009. Based on contract expirations and termination notices received in 2008 for 2009 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to increase 9.4% in 2009. This increase is due largely to the addition of compression at various facilities throughout the system as well as other projects designed to create incremental transportation capacity. Supply Corporation previously has been successful in marketing and obtaining executed contracts for available transportation capacity (at discounted rates when necessary), and expects this success to continue.

For the 2008-2009 winter period, Empire has service agreements in place for the full amount of its firm transportation capacity to its existing delivery points, totaling approximately 547 MDth per day. Most of Empire s firm capacity (91.2%) has been contracted as long-term full-year deals. A small number of those contracts are due to expire during fiscal 2009, representing 1.4% of Empire s firm capacity. In addition, Empire has some seasonal (winter-only) contracts that extend for multiple years, representing 2.7% of Empire s firm capacity. One of those seasonal contracts is due to expire during fiscal 2009; representing 1.1% of Empire s firm capacity. Arrangements for the remaining 6.1% of Empire s firm capacity are seasonal or annual contracts that expire before the end of fiscal 2009. Empire expects that all available capacity arising from expiring agreements will be re-contracted under new seasonal or annual agreements. The Utility segment accounts for approximately 7.8% of Empire s firm capacity, and the Energy Marketing segment accounts for approximately 1.9% of Empire s firm capacity, with the remaining 90.3% of Empire s firm capacity subject to contracts with nonaffiliated customers.

Upon the completion of the Empire Connector project, Empire will have expansion capacity for the 2008-2009 winter period. Empire has a firm service agreement for 150.7 MDth per day of this expansion capacity. This long-term full-year agreement represents approximately 60% of the Empire Connector expansion capacity. The Company continues to market the remaining capacity on both a firm and interruptible basis. None of this contracted expansion capacity will expire during fiscal 2009.

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 54.6% of the Company s 2008 net income available for common stock.

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Additional discussion of the Exploration and Production segment appears below under the headings Discontinued Operations, 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 2.2% of the Company s 2008 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.

**The Timber Segment**

The Timber segment s contribution to the Company s 2008 net income available for common stock was not significant.

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

**All Other Category and Corporate Operations**

The All Other category and Corporate operations contributed approximately 0.2% of the Company s 2008 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 August 2007, Seneca sold all of the issued and outstanding shares of SECI. SECI s operations are presented in the Company s financial statements as discontinued operations.

In July 2005, Horizon B.V. sold its entire 85.16% interest in United Energy, a.s. (U.E.), a district heating and electric generation business in the Czech Republic. United Energy s 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 2008, the Utility segment purchased 76.0 Bcf of gas for core market demand. All such purchases were made from non-affiliated companies. Gas purchased from producers and suppliers in the southwestern United States and Canada under firm contracts (seasonal and longer) accounted for 89% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 11% of the Utility segment s 2008 purchases. Purchases from Total Gas & Power North America Inc. (18%), Chevron Natural Gas (17%), ConocoPhillips Company (16%) and BP Canada (11%) accounted for 62% of the

Utility s 2008 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2008.

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

With respect to the Timber segment, Highland requires an adequate supply of timber to process in its sawmill and kiln operations. Fifty-two percent of the timber processed during 2008 in Highland s sawmill operations came from land owned by the Company s subsidiaries, and 48% came from outside sources. Timber cut for gas well drilling locations, access roads, and pipelines constituted an increasing portion of Highland s timber supply, both from land owned by the Company s subsidiaries and from outside sources. In addition, Highland purchased approximately 5.4 million board feet of green lumber to augment lumber supply for its kiln operations.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2008, this segment purchased 57 Bcf of gas, including 56 Bcf for core market demands. The remaining 1 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. In both New York and Pennsylvania, Distribution Corporation has retained substantial numbers of residential and small commercial customers as sales customers. However, for many years almost all the industrial and a substantial number of commercial customers have purchased their gas supplies from marketers and utilized Distribution Corporation s gas transportation services. Regulators in both New York and Pennsylvania have adopted retail competition programs for natural gas supply purchases by the remaining utility sales customers. To date, the Utility segment s traditional distribution function remains largely unchanged; however, in New York, the Utility segment has instituted a number of programs to accommodate more widespread customer choice. In Pennsylvania, the PaPUC issued a report in October 2005 that concluded effective competition does not exist in the retail natural gas supply market statewide. On September 11, 2008, the PaPUC adopted a Final Order and Action Plan designed to increase effective competition in the retail market for natural gas services. The plan sets forth a schedule of action items for utilities and the PaPUC in order to remove barriers in the market structure that, in the opinion of the PaPUC, prevented the full participation of unregulated natural gas suppliers in Pennsylvania retail markets.

Competition for 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 and may increase with electric utilities making retail energy sales.

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The Utility segment competes in its most vulnerable markets (the large commercial and industrial markets) by offering unbundled, flexible services. The Utility segment continues to develop or promote new sources and uses of natural gas or new services, rates and contracts. The Utility segment also emphasizes and provides high quality service to its customers.

**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 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. This location offers the opportunity for increased transportation and storage services in the future.

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 from Canadian sourced gas, and its facilities are readily expandable. These characteristics provide Empire the opportunity to compete for an increased share of the gas transportation markets. As noted above, Empire is constructing the Empire Connector project, which will expand its natural gas pipeline and enable Empire to serve new markets in New York and elsewhere in the Northeast. 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.

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, more recently, national marketers.

**Competition: The Timber Segment**

With respect to the Timber segment, Highland competes with other sawmill operations and with other suppliers of timber, logs and lumber. These competitors may be local, regional, national or international in scope. This competition, however, is primarily limited to those entities which either process or supply high quality hardwood species such as cherry, oak and maple as veneer logs, saw logs, export logs or lumber ultimately used in the production of high-end furniture, cabinetry and flooring. The Timber segment sells its products in domestic and international markets.

**Seasonality**

Variations in weather conditions can materially affect the volume of gas delivered by the Utility segment, as virtually all of its residential and commercial customers use 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 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.

Volumes transported and stored by Supply Corporation may vary materially depending on weather, without materially affecting its revenues. Supply Corporation 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.

Volumes transported by Empire may vary materially depending on weather, which can have a moderate effect on its revenues. Empire s allowed rates currently are based on a modified fixed-variable rate design, which allows recovery of most fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover variable costs associated with actual transportation of gas, to recover return on equity, and to recover income taxes. When Empire becomes a FERC-regulated interstate pipeline company (which is currently expected to occur in December 2008), Empire s allowed rates, like Supply Corporation s, will be based on a straight fixed-variable design. Under that rate design, weather-related variations in transportation volumes will not materially affect revenues.

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.

The activities of the Timber segment vary on a seasonal basis and are subject to weather constraints. Traditionally, the timber harvesting season occurs when timber growth is dormant and runs from approximately September to March. The operations conducted in the summer months typically focus on pulpwood and on thinning lower-grade or lower value trees from timber stands to encourage the growth of higher-grade or higher value trees.

**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 H Commitments and Contingencies.

**Miscellaneous**

The Company and its wholly owned or majority-owned subsidiaries had a total of 1,943 full-time employees at September 30, 2008. This is a decrease of approximately one-half of one percent from the 1,952 employees in the Company s U.S. operations at September 30, 2007.

In 2008 the Company entered into new agreements with collective bargaining units in New York. The new agreements went into effect in February 2008 and expire in February 2013. In November 2008 the Company entered into a new agreement with a collective bargaining unit in Pennsylvania. The agreement will go into effect in April 2009 and expire in April 2014. An agreement covering employees in another collective bargaining unit in Pennsylvania is scheduled to expire in May 2009. In November 2008 the Company reached a new agreement with the local leadership of that collective bargaining unit. The members of the collective bargaining unit are scheduled to vote on the agreement in December 2008.

The Utility segment has numerous municipal franchises under which it uses public roads and certain other rights-of-way and public property for the location of facilities. When necessary, the Utility segment renews such franchises.

The Company makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on the Company s internet website, www.nationalfuelgas.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. The information available at the Company s internet website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

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**Executive Officers of the Company as of November 15, 2008(1)**

| Name and Age (as of November 15, 2008) | Current Company Positions and Other Material Business Experience During Past Five Years |
|---|---|
| David F. Smith (55) | Chief Executive Officer of the Company since February 2008 and President of the Company since February 2006. Mr. Smith previously served as 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 April 2005 through January 2008; Vice President of the Company from April 2005 through January 2006; President of Distribution Corporation from July 1999 to April 2005; and Senior Vice President of Supply Corporation from July 2000 to April 2005. |
| Ronald J. Tanski (56) | Treasurer and Principal Financial Officer of the Company since April 2004; President of Supply Corporation since July 2008. Mr. Tanski previously served as President of Distribution Corporation from February 2006 through June 2008; Treasurer of Distribution Corporation from April 2004 through September 2008; Controller of the Company from February 2003 through March 2004; Senior Vice President of Distribution Corporation from July 2001 through January 2006; and Controller of Distribution Corporation from February 1997 through March 2004. |
| Matthew D. Cabell (50) | 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. From January 2002 to June 2003, Mr. Cabell served as a consultant assisting oil companies in upstream acquisition and divestment transactions as well as Gulf of Mexico entry strategy, first as an independent consultant and then as Vice President of Randall & Dewey, Inc., a major oil and gas transaction advisory firm. Mr. Cabell s prior employers are not subsidiaries or affiliates of the Company. |
| Anna Marie Cellino (55) | 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 September 2008; and Senior Vice President of Distribution Corporation from July 2001 through June 2008. |
| Karen M. Camiolo (49) | Controller and Principal Accounting Officer of the Company since April 2004; Controller of Distribution Corporation and Supply Corporation since April 2004; and Chief Auditor of the Company from July 1994 through March 2004. |
| Carl M. Carlotti (53) | 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 (48) | 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. |

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|---|---|
| Donna L. DeCarolis (49) | 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. |
| John R. Pustulka (56) | Senior Vice President of Supply Corporation since July 2001. |
| James D. Ramsdell (53) | 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, National Fuel depends on its operating subsidiaries to meet its financial obligations.***

National Fuel is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, National Fuel relies exclusively on repayments of principal and interest on intercompany loans made by National Fuel 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.

***Recent disruptions in financial markets may affect National Fuel s ability to obtain financing or refinance maturing debt on reasonable terms and may have other adverse effects.***

Widely-documented disruptions in financial markets have resulted in a severe tightening of credit availability in the United States. Liquidity in credit markets has contracted significantly, making terms for certain financings less attractive. Ongoing turmoil in the credit markets may make it difficult for National Fuel to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments and to refinance maturing debt on favorable terms. These difficulties could adversely affect National Fuel s operations and financial performance.

***National Fuel is dependent on bank credit facilities and continued access to capital markets to successfully execute its operating strategies.***

In addition to its longer term debt that is issued to the public under its indentures, National Fuel relies upon shorter term bank borrowings and commercial paper to finance a portion of its operations. National Fuel is dependent on these capital sources to provide capital to its subsidiaries to allow them to acquire, maintain and develop their properties. The availability and cost of these credit sources is cyclical and these capital sources may not remain available to National Fuel or National Fuel may not be able to obtain money at a reasonable cost in the future. Recent access to the commercial paper markets has been on less favorable terms as a result of ongoing turmoil in the credit markets, and the commercial paper markets may not consistently be a reliable source of short-term financing for National Fuel in the future. National Fuel s ability to borrow under its credit facilities and commercial paper agreements depends on National Fuel s compliance with its obligations under the facilities and agreements. In addition, all of National Fuel 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. At present, National Fuel has no active interest rate hedges in place to protect against interest rate fluctuations on short-term bank debt. In addition, the interest rates on National Fuel s short-term bank loans and the ability of National Fuel 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. On October 15, 2008, National Fuel s senior unsecured credit rating of BBB+ was placed on CreditWatch-with negative implications by S&P. A ratings downgrade could increase the interest cost of debt issued by National Fuel and decrease future availability of money from banks, commercial paper purchasers and other sources. National Fuel s debt securities are currently rated at investment grade and the Company believes it is important to maintain investment grade credit ratings to conduct its business.

***National Fuel 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 National Fuel s revenues and cash flows or restrict its future growth. Economic conditions in National Fuel s utility service territories and energy marketing territories also impact its collections of accounts receivable. All of National Fuel 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 National Fuel s commodity hedging arrangements might not be able to perform their obligations under these arrangements. Customers of National Fuel 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 National Fuel s results of operations, financial condition and cash flows.

***The increasing costs of certain employee and retiree benefits could adversely affect National Fuel s results.***

National Fuel 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 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, National Fuel might not be able to mitigate the rising costs of medical benefits. Increases to the costs of pension and medical benefits could have an adverse effect on National Fuel s financial results.

***National Fuel s credit ratings may not reflect all the risks of an investment in its securities.***

National Fuel 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. National Fuel 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.

***National Fuel 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 National Fuel 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 National Fuel 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 affect its business in ways that the Company cannot predict.

In its Utility segment, the operations of Distribution Corporation are subject to the jurisdiction of the NYPSC and the PaPUC. 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 if 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 sought to establish competitive markets in which customers may purchase supplies of gas from marketers, rather than from utility companies. In June 1999, the Governor of Pennsylvania signed into law the Natural Gas Choice and Competition Act. The Act revised the Public Utility Code relating to the restructuring of the natural gas industry, to permit consumer choice of natural gas suppliers. The early programs instituted to comply with the Act did not result in significant change, and many residential customers currently continue to purchase natural gas from the utility companies. In October 2005, the PaPUC concluded that effective competition does not exist in the retail natural gas supply market statewide. On September 11, 2008, the PaPUC adopted a Final Order and Action Plan designed to increase effective competition in the retail market for natural gas services. The plan sets forth a schedule of action items for utilities and the PaPUC in order to remove barriers in the market structure that, in the opinion of the PaPUC, prevented the full participation of unregulated natural gas suppliers in Pennsylvania retail markets. In New York, in August 2004, the NYPSC issued its Statement of Policy on Further Steps Toward Competition in Retail Energy Markets. This policy statement has a similar goal of encouraging customer choice of alternative natural gas providers. In 2005, the NYPSC stepped up its efforts to encourage customer choice at the retail residential level, and customer choice activities increased in Distribution Corporation s New York service territory. In April 2007, the NYPSC, noting that the retail energy marketplace in New York is established and continuing to expand, commenced a review to determine if existing programs initially designed to promote competition had outlived their usefulness and whether the cost of programs currently funded by utility rate payers should be shifted to market competitors. Increased retail choice activities, to the extent they occur, may increase Distribution Corporation s cost of doing business, put an additional portion of its business at regulatory risk, and create uncertainty for the future, all of which may make it more difficult to manage Distribution Corporation s business profitably.

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 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 its Pipeline and Storage segment, National Fuel is subject to the jurisdiction of the FERC with respect to Supply Corporation, and to the jurisdiction of the NYPSC with respect to Empire. The FERC has authorized Empire to construct and operate the Empire Connector project. When Empire completes construction and commences operations of the Empire Connector, Empire will at that time become a FERC-regulated pipeline company. The FERC and the NYPSC, among other things, approve the rates that Supply Corporation and Empire, respectively, 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 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.

***National Fuel 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 National Fuel s capital resources. National Fuel has issued commercial paper and used short-term borrowings in the past to temporarily finance storage inventories and purchased gas costs, and although National Fuel 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 National Fuel s ability to finance capital expenditures and to refinance maturing debt.***

National Fuel 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, National Fuel 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, National Fuel s authorized rate of return could be reduced. If interest rates are higher than assumed rates, National Fuel s ability to earn its authorized rate of return may be adversely impacted.

***Decreased oil and natural gas prices could adversely affect revenues, cash flows and profitability.***

National Fuel s exploration and production operations 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 natural gas transportation, royalties, and price controls. National Fuel sells most of its oil and natural gas at current market prices rather than through fixed-price contracts, although as discussed below, National Fuel frequently hedges the price of a significant portion of its future production in the financial markets. The prices National Fuel receives depend upon factors beyond National Fuel s control, including the factors affecting price mentioned above. National Fuel believes that any prolonged reduction in oil and natural gas prices would restrict its ability to continue the level of exploration and production activity National Fuel otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.

***National Fuel 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, National Fuel periodically 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 National Fuel s expected energy production during the upcoming 12-month period. These contracts reduce exposure to subsequent price drops but can also limit National Fuel 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 volumes of gas stored underground. National Fuel s Pipeline and Storage segment enters into hedging arrangements with respect to certain sales of efficiency gas, and the All Other category has hedging arrangements in place with respect to certain volumes of landfill gas committed for sale.

Under applicable accounting rules, 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 National Fuel 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 National Fuel 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 and the All Other category. National Fuel maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose National Fuel 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 National Fuel s proved oil and natural gas reserves and the future net cash flows from those reserves that were prepared by National Fuel s petroleum engineers and audited by independent petroleum engineers. Petroleum engineers consider many factors and make assumptions in estimating National Fuel s 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 National Fuel s reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of National Fuel 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 National Fuel 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 National Fuel s proved reserves is the current market value of National Fuel s estimated oil and natural gas reserves. In accordance with SEC requirements, National Fuel bases the estimated discounted future net cash flows from its proved reserves on prices and costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of National Fuel 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 National Fuel 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 National Fuel 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 National Fuel 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 National Fuel s earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. National Fuel 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, 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 National Fuel may not recover all or any portion of its investment. Without continued successful exploitation or acquisition activities, National Fuel s reserves and revenues will decline as a result of its current reserves being depleted by production. National Fuel cannot assure you that it will be able to find or acquire additional reserves at acceptable costs.

***Financial accounting requirements regarding exploration and production activities may affect National Fuel s profitability.***

National Fuel accounts for its exploration and production activities under the full cost method of accounting. Each quarter, National Fuel 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 quarter-end spot prices for oil and natural gas (as 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 National Fuel to recognize an immediate expense in that quarter, and its earnings would be reduced. National Fuel s Exploration and Production segment last recorded an impairment charge under the full cost method of accounting in 2006. Because of the variability in National Fuel s investment in oil and natural gas properties and the volatile nature of commodity prices, National Fuel cannot predict when in the future it may again be affected by such an impairment calculation.

***Environmental regulation significantly affects National Fuel s business.***

National Fuel 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 into the environment and the general protection of public health, natural resources, wildlife and the environment. Costs of compliance and liabilities could negatively affect National Fuel s results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at National Fuel s facilities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect National Fuel s business. Although National Fuel cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local regulations, National Fuel s costs could increase if environmental laws and regulations become more strict.

***The nature of National Fuel s operations presents inherent risks of loss that could adversely affect its results of operations, financial condition and cash flows.***

National Fuel s operations in its various 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, National Fuel 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, National Fuel maintains insurance coverage against some, but not all, potential losses. In addition, many of the agreements that National Fuel executes with contractors provide for the division of responsibilities between the contractor and National Fuel, and National Fuel seeks to obtain an indemnification from the contractor for certain of these risks. National Fuel is not always able, however, to secure written agreements with its contractors that contain indemnification, and sometimes National Fuel is required to indemnify others.

Insurance or indemnification agreements when obtained may not adequately protect National Fuel 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 National Fuel. 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, National Fuel 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 National Fuel s results of operations, financial condition and cash flows.

Hazards and risks faced by National Fuel, and insurance and indemnification obtained or provided by National Fuel, may subject National Fuel to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against National Fuel or be resolved on unfavorable terms, the result of which could have a material adverse effect on National Fuel s results of operations, financial condition and cash flows.

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

In January 2008, National Fuel 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 National Fuel s Board of Directors at National Fuel s 2008 Annual Meeting of Stockholders. Pursuant to the settlement agreement, National

Fuel and Vantage agreed, among other things, to a standstill whereby, until September 2009, Vantage will not, among other things, acquire voting securities that would increase its beneficial ownership to more than 9.6% of National Fuel s voting securities; engage in any proxy solicitations or advance any shareholder proposals; attempt to control National Fuel s Board of Directors, management or policies; call a meeting of shareholders; obtain additional representation to the Board of Directors; or effect the removal of any member of the Board of Directors. At the end of the standstill period, Vantage may again seek to effect changes at National Fuel or acquire control over National Fuel. In addition, other existing or potential shareholders may engage in proxy solicitations, advance shareholder proposals or otherwise attempt to effect changes or acquire control over National Fuel.

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 changes in strategy or management, changes to the board of directors, restructuring, increased financial leverage, 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 National Fuel s operations and diverting the attention of National Fuel s Board of Directors and senior management. As a result, shareholder campaigns could adversely affect National Fuel 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 $3.2 billion at September 30, 2008. Approximately 62% of this investment was in the Utility and Pipeline and Storage segments, which are primarily located 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 (35%), is primarily located in California, in the Appalachian region of the United States, in Wyoming, and in the Gulf Coast region of Texas, Louisiana, and Alabama. The remaining net investment in property, plant and equipment consisted of the Timber segment (2%) which is located primarily in northwestern Pennsylvania, and All Other and Corporate operations (1%). 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 $163.1 million, or 5.5%, since 2003. 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. In addition, during 2005, the Company sold its majority interest in U.E., a district heating and electric generation business in the Czech Republic. The net property, plant and equipment of U.E. at the date of sale was $223.9 million.

The Utility segment had a net investment in property, plant and equipment of $1.1 billion at September 30, 2008. The net investment in its gas distribution network (including 14,819 miles of distribution pipeline) and its service connections to customers represent approximately 52% and 34%, respectively, of the Utility segment s net investment in property, plant and equipment at September 30, 2008.

The Pipeline and Storage segment had a net investment of $826.5 million in property, plant and equipment at September 30, 2008. Transmission pipeline represents 27% of this segment s total net investment and includes 2,371 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 21% 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 429 miles of pipeline. Net investment in storage facilities includes $94.8 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 27 compressor stations with 75,104 installed compressor horsepower that represent 11% 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 $1.1 billion at September 30, 2008.

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The Timber segment had a net investment in property, plant and equipment of $86.4 million at September 30, 2008. Located primarily in northwestern Pennsylvania, the net investment includes two sawmills, 103,680 acres of land and timber, and 3,122 acres of timber rights.

The Utility and Pipeline and Storage segments facilities provided the capacity to meet the Company s 2008 peak day sendout, including transportation service, of 1,632 MMcf, which occurred on February 10, 2008. Withdrawals from storage of 768.3 MMcf provided approximately 47.1% 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, in Wyoming, and in the Gulf Coast region of Texas, Louisiana, and Alabama. 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 the sale of the Canadian oil and gas properties is included in Item 8, Note I Discontinued Operations. Further discussion of oil and gas producing activities is included in Item 8, Note O Supplementary Information for Oil and Gas Producing Activities. Note O sets forth proved developed and undeveloped reserve information for Seneca. Seneca s proved developed and undeveloped natural gas reserves increased from 205 Bcf at September 30, 2007 to 226 Bcf at September 30, 2008. This increase is attributed primarily to extensions and discoveries (40.1 Bcf), primarily in the Appalachian region (31.3 Bcf). This increase was partially offset by production of 22.3 Bcf. Seneca s proved developed and undeveloped oil reserves decreased from 47,586 Mbbl at September 30, 2007 to 46,198 Mbbl at September 30, 2008. This decrease is attributed to production (3,070 Mbbl), primarily occurring in California (2,460 Mbbl) and sales of minerals in place (1,334 Mbbl). These decreases were partially offset by purchases of minerals in place (2,084 Mbbl) and extensions and discoveries (827 Mbbl). On a Bcfe basis, Seneca s proved developed and undeveloped reserves increased from 491 Bcfe at September 30, 2007 to 503 Bcfe at September 30, 2008. Seneca s proved developed and undeveloped natural gas reserves decreased from 233 Bcf at September 30, 2006 to 205 Bcf at September 30, 2007. This decrease is attributed primarily to the sale of the Canadian gas properties (40.1 Bcf) and production of 26.3 Bcf. These decreases were partially offset by extensions and discoveries of 34.6 Bcf, primarily in the Appalachian region (29.7 Bcf). Seneca s proved developed and undeveloped oil reserves decreased from 58,018 Mbbl at September 30, 2006 to 47,586 Mbbl at September 30, 2007. This decrease is attributed to revisions of previous estimates (5,963 Mbbl), primarily occurring in California, production (3,450 Mbbl) and the sale of the Canadian oil properties (1,458 Mbbl). On a Bcfe basis, Seneca s proved developed and undeveloped reserves decreased from 581 Bcfe at September 30, 2006 to 491 Bcfe at September 30, 2007.

Seneca s oil and gas reserves reported in Item 8 at Note O as of September 30, 2008 were estimated by Seneca s geologists and engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Seneca reports its oil and gas reserve information on an annual basis to the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy. The oil and gas reserve information reported to the EIA showed 204 Bcf and 49,899 Mbbl of gas and oil reserves, respectively, which differs from the reserve information summarized in Item 8 at Note O. The reasons for this difference are as follows: (a) reserves are reported to the EIA on a calendar year basis, while reserves disclosed in Item 8 at Note O are shown on a fiscal year basis; (b) reserves reported to the EIA include only properties operated by Seneca, while reserves disclosed in Item 8 at Note O included both Seneca operated properties and non-operated properties in which Seneca has an interest; and (c) reserves are reported to the EIA on a gross basis versus the reserves disclosed in Item 8 at Note O, which are reported on a net revenue interest basis.

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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 | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| **United States** | | | |
| Gulf Coast Region | | | |
| Average Sales Price per Mcf of Gas | $ 10.03 | $ 6.58 | $ 8.01 |
| Average Sales Price per Barrel of Oil | $ 107.27 | $ 63.04 | $ 64.10 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 9.49 | $ 6.87 | $ 5.89 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 98.56 | $ 64.09 | $ 47.46 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.63 | $ 1.08 | $ 0.86 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 38 | 40 | 36 |
| West Coast Region | | | |
| Average Sales Price per Mcf of Gas | $ 8.71 | $ 6.54 | $ 7.93 |
| Average Sales Price per Barrel of Oil | $ 98.17 | $ 56.86 | $ 56.80 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 8.22 | $ 6.82 | $ 7.19 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 77.64 | $ 47.43 | $ 37.69 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 2.01 | $ 1.54 | $ 1.35 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 51 | 50 | 53 |
| Appalachian Region | | | |
| Average Sales Price per Mcf of Gas | $ 9.73 | $ 7.48 | $ 9.53 |
| Average Sales Price per Barrel of Oil | $ 97.40 | $ 62.26 | $ 65.28 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 8.85 | $ 8.25 | $ 8.90 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 97.40 | $ 62.26 | $ 65.28 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 0.77 | $ 0.69 | $ 0.69 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 22 | 17 | 15 |
| **Total United States** | | | |
| Average Sales Price per Mcf of Gas | $ 9.70 | $ 6.82 | $ 8.42 |
| Average Sales Price per Barrel of Oil | $ 99.64 | $ 58.43 | $ 58.47 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 9.05 | $ 7.25 | $ 7.02 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 81.75 | $ 51.68 | $ 40.26 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.64 | $ 1.23 | $ 1.09 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 111 | 108 | 104 |

| | For The Year Ended September 30 2008 | 2007 | 2006 |
|---|---|---|---|
| **Canada Discontinued Operations** | | | |
| Average Sales Price per Mcf of Gas | $ | $ 6.09 | $ 7.14 |
| Average Sales Price per Barrel of Oil | $ | $ 50.06 | $ 51.40 |
| Average Sales Price per Mcf of Gas (after hedging) | $ | $ 6.17 | $ 7.47 |
| Average Sales Price per Barrel of Oil (after hedging) | $ | $ 50.06 | $ 51.40 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ | $ 1.94 | $ 1.57 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | | 21 | 26 |
| **Total Company** | | | |
| Average Sales Price per Mcf of Gas | $ 9.70 | $ 6.64 | $ 8.04 |
| Average Sales Price per Barrel of Oil | $ 99.64 | $ 57.93 | $ 57.94 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 9.05 | $ 6.98 | $ 7.15 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 81.75 | $ 51.58 | $ 41.10 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.64 | $ 1.35 | $ 1.18 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 111 | 129 | 130 |

**Productive Wells**

| At September 30, 2008 | | Gulf Coast Region Gas | Gulf Coast Region Oil | West Coast Region Gas | West Coast Region Oil | Appalachian Region Gas | Appalachian Region Oil | Total Company Gas | Total Company Oil |
|---|---|---|---|---|---|---|---|---|---|
| Productive Wells | Gross | 25 | 42 | | 1,437 | 2,641 | 6 | 2,666 | 1,485 |
| Productive Wells | Net | 14 | 14 | | 1,426 | 2,570 | 5 | 2,584 | 1,445 |

**Developed and Undeveloped Acreage**

| At September 30, 2008 | Gulf Coast Region | West Coast Region | Appalachian Region | Total Company |
|---|---|---|---|---|
| Developed Acreage | | | | |
| Gross | 113,934 | 11,360 | 531,743 | 657,037 |
| Net | 80,852 | 10,945 | 501,411 | 593,208 |
| Undeveloped Acreage | | | | |
| Gross | 142,118 | | 458,894 | 601,012 |
| Net | 102,831 | | 438,040 | 540,871 |

As of September 30, 2008, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 38,811 acres in 2009 (23,289 net acres), 23,302 acres in 2010 (11,754 net acres), 82,165 acres in 2011 (67,472 net acres), and 456,734 acres thereafter (438,356 net acres).

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**Drilling Activity**

| For the Year Ended September 30 | Productive 2008 | 2007 | 2006 | Dry 2008 | 2007 | 2006 |
|---|---|---|---|---|---|---|
| **United States** | | | | | | |
| Gulf Coast Region | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | 1.14 | 1.31 | 2.94 | 0.37 | 1.42 | 0.85 |
| Development | | 1.00 | 0.78 | | 0.67 | |
| West Coast Region | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | 1.00 | 0.50 | | | | |
| Development | 62.00 | 58.99 | 92.98 | 1.00 | 2.00 | 1.00 |
| Appalachian Region | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | 8.00 | 8.10 | 3.88 | 1.00 | | |
| Development | 186.00 | 184.00 | 140.58 | | 2.00 | 1.75 |
| Total United States | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | 10.14 | 9.91 | 6.82 | 1.37 | 1.42 | 0.85 |
| Development | 248.00 | 243.99 | 234.34 | 1.00 | 4.67 | 2.75 |
| **Canada Discontinued Operations** | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | | 6.38 | 12.60 | | | 1.35 |
| Development | | 1.80 | 2.50 | | | 1.00 |
| **Total** | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | 10.14 | 16.29 | 19.42 | 1.37 | 1.42 | 2.20 |
| Development | 248.00 | 245.79 | 236.84 | 1.00 | 4.67 | 3.75 |

**Present Activities**

| At September 30, 2008 | Gulf Coast Region | West Coast Region | Appalachian Region | Total Company |
|---|---|---|---|---|
| Wells in Process of Drilling(1) | | | | |
| Gross | 2.00 | 1.00 | 148.00 | 151.00 |
| Net | 0.59 | 1.00 | 146.00 | 147.59 |

(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 H 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.

**Item 4** ***Submission of Matters to a Vote of Security Holders***

No matter was submitted to a vote of security holders during the quarter ended September 30, 2008.

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

On July 2, 2008, the Company issued a total of 2,400 unregistered shares of Company common stock to the eight non-employee directors of the Company then serving on the Board of Directors of the Company and receiving compensation under the Company s Retainer Policy for Non-Employee Directors, 300 shares to each such director. All of these unregistered shares were issued as partial consideration for such directors services during the quarter ended September 30, 2008. 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, 2008 | 6,404 | $ 54.02 | | 1,332,725 |
| Aug. 1-31, 2008 | 544,982 | $ 46.72 | 537,165 | 795,560 |
| Sept. 1-30, 2008 | 1,832,488 | $ 45.08 | 1,824,541 | 6,971,019 |
| Total | 2,383,874 | $ 45.48 | 2,361,706 | 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, (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, and (iii) shares of common stock of the Company purchased on the open market pursuant to the Company s publicly announced share repurchase program. Shares purchased other than through a publicly announced share repurchase program totaled 6,404 in July 2008, 7,817 in August 2008 and 7,947 in September 2008 (a three-month total of 22,168). All of those shares were purchased for the Company s 401(k) plans.

(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 had, however, stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. However, such repurchases may be made in the future if conditions improve. Such repurchases would be made in the open market or through private transactions.

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**Item 6** ***Selected Financial Data***

| | Year Ended September 30 | | | | |
|---|---|---|---|---|---|
| | 2008 | 2007 | 2006 | 2005 | 2004 |
| | | | (Thousands) | | |
| **Summary of Operations** | | | | | |
| Operating Revenues | $ 2,400,361 | $ 2,039,566 | $ 2,239,675 | $ 1,860,774 | $ 1,867,875 |
| Operating Expenses: | | | | | |
| Purchased Gas | 1,235,157 | 1,018,081 | 1,267,562 | 959,827 | 949,452 |
| Operation and Maintenance | 432,871 | 396,408 | 395,289 | 388,094 | 374,010 |
| Property, Franchise and Other Taxes | 75,585 | 70,660 | 69,202 | 68,164 | 68,378 |
| Depreciation, Depletion and Amortization | 170,623 | 157,919 | 151,999 | 156,502 | 159,184 |
| | 1,914,236 | 1,643,068 | 1,884,052 | 1,572,587 | 1,551,024 |
| Loss on Sale of Timber Properties | | | | | (1,252) |
| Operating Income | 486,125 | 396,498 | 355,623 | 288,187 | 315,599 |
| Other Income (Expense): | | | | | |
| Income from Unconsolidated Subsidiaries | 6,303 | 4,979 | 3,583 | 3,362 | 805 |
| Impairment of Investment in Partnership | | | | (4,158) | |
| Interest Income | 10,815 | 1,550 | 9,409 | 6,236 | 1,771 |
| Other Income | 7,376 | 4,936 | 2,825 | 12,744 | 2,908 |
| Interest Expense on Long-Term Debt | (70,099) | (68,446) | (72,629) | (73,244) | (82,989) |
| Other Interest Expense | (3,870) | (6,029) | (5,952) | (9,069) | (6,354) |
| Income from Continuing Operations Before Income Taxes | 436,650 | 333,488 | 292,859 | 224,058 | 231,740 |
| Income Tax Expense | 167,922 | 131,813 | 108,245 | 85,621 | 89,820 |
| Income from Continuing Operations | 268,728 | 201,675 | 184,614 | 138,437 | 141,920 |
| Discontinued Operations: | | | | | |
| Income (Loss) from Operations, Net of Tax | | 15,479 | (46,523) | 25,277 | 24,666 |
| Gain on Disposal, Net of Tax | | 120,301 | | 25,774 | |
| Income (Loss) from Discontinued Operations, Net of Tax | | 135,780 | (46,523) | 51,051 | 24,666 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Net Income Available for Common Stock | $ | 268,728 | $ | 337,455 | $ | 138,091 | $ | 189,488 | $ | 166,586 |

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| | Year Ended September 30 2008 | 2007 | 2006 (Thousands) | 2005 | 2004 |
|---|---|---|---|---|---|
| **Per Common Share Data** | | | | | |
| Basic Earnings from Continuing Operations per Common Share | $ 3.27 | $ 2.43 | $ 2.20 | $ 1.66 | $ 1.73 |
| Diluted Earnings from Continuing Operations per Common Share | $ 3.18 | $ 2.37 | $ 2.15 | $ 1.63 | $ 1.71 |
| Basic Earnings per Common Share(1) | $ 3.27 | $ 4.06 | $ 1.64 | $ 2.27 | $ 2.03 |
| Diluted Earnings per Common Share(1) | $ 3.18 | $ 3.96 | $ 1.61 | $ 2.23 | $ 2.01 |
| Dividends Declared | $ 1.27 | $ 1.22 | $ 1.18 | $ 1.14 | $ 1.10 |
| Dividends Paid | $ 1.26 | $ 1.21 | $ 1.17 | $ 1.13 | $ 1.09 |
| Dividend Rate at Year-End | $ 1.30 | $ 1.24 | $ 1.20 | $ 1.16 | $ 1.12 |
| At September 30: | | | | | |
| **Number of Registered Shareholders** | 16,544 | 16,989 | 17,767 | 18,369 | 19,063 |
| **Net Property, Plant and Equipment** | | | | | |
| Utility | $ 1,125,859 | $ 1,099,280 | $ 1,084,080 | $ 1,064,588 | $ 1,048,428 |
| Pipeline and Storage | 826,528 | 681,940 | 674,175 | 680,574 | 696,487 |
| Exploration and Production(2) | 1,095,960 | 982,698 | 1,002,265 | 974,806 | 923,730 |
| Energy Marketing | 98 | 102 | 59 | 97 | 80 |
| Timber | 86,392 | 89,902 | 90,939 | 94,826 | 82,838 |
| All Other | 11,946 | 16,735 | 17,394 | 18,098 | 21,172 |
| Corporate(3) | 7,317 | 7,748 | 8,814 | 6,311 | 234,029 |
| Total Net Plant | $ 3,154,100 | $ 2,878,405 | $ 2,877,726 | $ 2,839,300 | $ 3,006,764 |
| **Total Assets** | $ 4,130,187 | $ 3,888,412 | $ 3,763,748 | $ 3,749,753 | $ 3,738,103 |
| **Capitalization** | | | | | |
| Comprehensive Shareholders Equity | $ 1,603,599 | $ 1,630,119 | $ 1,443,562 | $ 1,229,583 | $ 1,253,701 |
| Long-Term Debt, Net of Current Portion | 999,000 | 799,000 | 1,095,675 | 1,119,012 | 1,133,317 |
| Total Capitalization | $ 2,602,599 | $ 2,429,119 | $ 2,539,237 | $ 2,348,595 | $ 2,387,018 |

(1) Includes discontinued operations.

(2) Includes net plant of SECI discontinued operations as follows: $0 for 2008 and 2007, $88,023 for 2006, $170,929 for 2005, and $142,860 for 2004.

(3) Includes net plant of the former international segment as follows: $29 for 2008, $38 for 2007, $27 for 2006, $20 for 2005, and $227,905 for 2004.

## 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 five business segments. Refer to Item 1, Business, for a more detailed description of each of the segments. This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, Results of Operations;
3. Operating, investing and financing cash flows under the heading Capital Resources and Liquidity;
4. Off-Balance Sheet Arrangements;
5. Contractual Obligations; and
6. Other Matters, including: (a) 2008 and 2009 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 accounting pronouncements.

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

Overall, 2008 was a strong year for the Company. Income from continuing operations in 2008 benefited primarily from higher crude oil and natural gas prices in the Exploration and Production segment combined with an overall increase in natural gas production, primarily in the Appalachian region. These factors led to a $67.1 million increase in income from continuing operations compared to the prior year. In 2007, the Company recorded $135.8 million of income from discontinued operations, consisting of a $120.3 million gain, net of tax, on the sale of SECI and $15.5 million of income from SECI prior to its sale in August 2007. SECI, Seneca s wholly owned subsidiary, was engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in the provinces of Alberta, Saskatchewan and British Columbia in Canada. Combining both income from continuing operations and discontinued operations, the Company s net income available for common stock decreased $68.7 million in 2008 compared to the prior year. The Company s earnings are discussed further in the Results of Operations section that follows.

The Company spent $414.5 million on capital expenditures during 2008, with approximately 46 percent being spent in the Exploration and Production segment and 40 percent being spent in the Pipeline and Storage segment. Management continues to believe that these segments provide the best earnings growth opportunities for shareholders. In the Exploration and Production segment, the Company s principal focus continues to be the development of its nearly one million acres in the Appalachian region along with continued exploration and development in the Gulf and West Coast regions. In the Pipeline and Storage segment, the majority of the expenditures were for construction costs of the Empire Connector project. The Empire Connector is anticipated to be ready to commence service in December 2008 on or before the in-service date of the Millennium Pipeline. The Company s capital expenditure program is discussed further in the Capital Resources and Liquidity section that follows.

Despite the positives mentioned above, the economy of the United States has become constrained by significant volatility and turmoil in the capital and credit markets. The government s Troubled Asset Relief Program and decreases in federal funds rates have not been enough to stem the reluctance on the part of lenders to extend credit to businesses. In the current period these events have not had a material impact on the Company, although further disruption in the markets and tightening of credit availability could negatively impact future periods. At September 30, 2008, the Company had a strong balance sheet and liquidity. The Company had no outstanding short-term notes payable to banks or commercial paper at that date. However, since that date, the Company has borrowed short-term funds under its credit lines and through the commercial paper market to fund working capital needs. The Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. These credit lines, which aggregate to $420.0 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 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 that extends through September 30, 2010.

During 2006, the Company began repurchasing outstanding shares of common stock under a share repurchase program authorized by the Company s Board of Directors. The program authorized the Company to repurchase up to an aggregate amount of eight million shares. This threshold was reached 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. Under this new authorization, the Company repurchased 1,028,981 shares for $46.0 million through September 17, 2008. The Company stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. However, such repurchases may be made in the future if conditions improve.

During 2009, the Company expects to finance its capital expenditure program, dividends, and operating expenses (including Retirement Plan and other post-retirement benefit funding) with cash from operations, proceeds from the sale of assets, and/or short-term borrowings. As oil and gas commodity prices have decreased significantly from their highs during 2008, it is possible that the Company may have to rely more heavily on short-term borrowings to meet its cash needs. It is also possible that the Company may choose to reduce its 2009 capital expenditures.

With the turmoil in the credit markets has come a significant decline in the stock markets. This has had a significant impact on the asset values of the Company s Retirement Plan and its VEBA trusts and 401(h) accounts. The Company anticipates funding $15.0 million to $20.0 million to the Retirement Plan and $25.0 million to $30.0 million to its VEBA trusts and 401(h) accounts during 2009. However, under the current funding requirements of the Pension Protection Act, should market conditions at September 30, 2008 remain unchanged, contributions in future years could increase significantly. This issue is discussed further in the Other Matters section that follows.

## 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 current market prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The 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. Because of the decline in the price of natural gas during the third and fourth quarters of 2006, the book value of the Company s Canadian oil and gas properties exceeded the ceiling at both June 30, 2006 and September 30, 2006. Consequently, SECI recorded impairment charges of $62.4 million ($39.5 million after-tax) in the third quarter of 2006 and $42.3 million ($29.1 million after-tax) in the fourth quarter of 2006. These impairment charges are included in the loss from discontinued operations for 2006 due to the sale of SECI during 2007. At September 30, 2008, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $500 million. Declines in commodity prices since that date have reduced the ceiling. Using more up to date pricing of $6 per Mcf for natural gas and $60 per barrel for crude oil, the ceiling at September 30, 2008 would have exceeded the book value of the Company s oil and gas properties by approximately $80 million.

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.

Upon the adoption of SFAS 143 on October 1, 2002, the Company recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment s crude oil and natural gas wells and capitalized such costs in property, plant and equipment (i.e. the full cost pool). Prior to the adoption of SFAS 143, plugging and abandonment costs were accounted for solely through the Company s units-of-production depletion calculation. An estimate of such costs was added to the depletion base, which also included capitalized costs in the full cost pool and estimated future expenditures to be incurred in developing proved reserves. With the adoption of SFAS 143, plugging and abandonment costs are already included in capitalized costs and the units-of-production depletion calculation has been modified to exclude from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

Prior to the adoption of SFAS 143, in calculating the full cost ceiling, the Company reduced the future net cash flows from proved oil and gas reserves by the estimated plugging and abandonment costs. Such future net cash flows would then be compared to capitalized costs in the full cost pool, with any excess capitalized costs being expensed. With the adoption of SFAS 143, since the full cost pool now includes an amount associated with plugging and abandoning the wells, the calculation of the full cost ceiling has been changed so that future net cash flows from proved oil and gas reserves are no longer reduced by the estimated 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 SFAS 71, 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, Pipeline and Storage segment and All Other category, 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, no cost collars and futures contracts. The Company, in its Pipeline and Storage segment, previously used an interest rate collar to limit interest rate fluctuations on certain variable rate debt. In accordance with the provisions of SFAS 133, the Company accounted for these instruments as effective cash flow hedges or fair value hedges. In 2007, the Company discontinued hedge accounting for the interest rate collar, which resulted in a gain being recognized. 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 fair values of the non exchange-traded derivative financial instruments are based on valuations determined by the counterparties. The Company used a model to substantiate the values reported by the counterparties. At September 30, 2008, the Company established a credit reserve of $0.6 million against the asset recorded on its books for non-exchange traded derivative financial instruments. The credit reserve was determined by applying default probabilities to the anticipated cash flows that the Company is expecting from its counterparties. 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 represented 97% and 93%, respectively, of the Company s total pension and post-retirement benefit costs as determined under SFAS 87 and SFAS 106 for the years ended September 30, 2008 and 2007.

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 6.25% in 2007 to 6.75% in 2008. The change in the discount rate from 2007 to 2008 reduced the Retirement Plan projected benefit obligation by $38.6 million and the accumulated post-retirement benefit obligation by $26.3 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 2008, actual versus expected return on plan assets resulted in a decrease to the funded status of the Retirement Plan ($94.2 million) and the VEBA trusts and 401(h) accounts ($77.2 million). The actual versus expected benefit payments for 2008 caused an increase of $0.1 million to the projected benefit obligation and a decrease of $3.6 million to the accumulated post-retirement benefit obligation, respectively. 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 11 years for the Retirement Plan and 13 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 the adoption of SFAS 158, and to Item 8 at Note G Retirement Plan and Other Post Retirement Benefits.

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## RESULTS OF OPERATIONS

### EARNINGS

#### 2008 Compared with 2007

The Company s earnings were $268.7 million in 2008 compared with earnings of $337.5 million in 2007. As previously discussed, the Company presented its Canadian operations in the Exploration and Production segment (in conjunction with the sale of SECI) as discontinued operations. The Company s earnings from continuing operations were $268.7 million in 2008 compared with $201.7 million in 2007. The Company s earnings from discontinued operations were $135.8 million in 2007. The increase in earnings from continuing operations is primarily the result of higher earnings in the Exploration and Production and Utility segments and the All Other category, slightly offset by lower earnings in the Corporate category and the Timber, Pipeline and Storage, and Energy Marketing segments, as shown in the table below. 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 several events in 2008 and 2007, including:

***2008 Events***

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

***2007 Events***

A $120.3 million gain on the sale of SECI, which was completed in August 2007. This amount is included in earnings from discontinued operations;

A $4.8 million benefit to earnings in the Pipeline and Storage segment due to the reversal of a reserve established for all costs incurred related to the Empire Connector project recognized during June 2007;

A $1.9 million benefit to earnings in the Pipeline and Storage segment associated with the discontinuance of hedge accounting for Empire s interest rate collar; and

A $2.3 million benefit to earnings in the Energy Marketing segment related to the resolution of a purchased gas contingency.

#### 2007 Compared with 2006

The Company s earnings were $337.5 million in 2007 compared with earnings of $138.1 million in 2006. As previously discussed, the Company has presented its Canadian operations in the Exploration and Production segment (in conjunction with the sale of SECI) as discontinued operations. The Company s earnings from continuing operations were $201.7 million in 2007 compared with $184.6 million in 2006. The Company s earnings from discontinued operations were $135.8 million in 2007 compared with a loss of $46.5 million in 2006. The increase in earnings from continuing operations of $17.1 million is primarily the result of higher earnings in the Exploration and Production, Utility, Pipeline and Storage, and Energy Marketing segments and the Corporate and All Other categories, slightly offset by lower earnings in the Timber segment, as shown in the table below. The increase in earnings from discontinued operations primarily resulted from the gain on the sale of SECI recognized in 2007 as well as the non-recurrence of $68.6 million of impairment charges recognized in 2006 related to the Exploration and Production segment s Canadian oil and gas assets. Earnings from continuing operations and discontinued operations were impacted by several events discussed above and the following 2006 events:

*2006 Events*

$68.6 million of impairment charges related to the Exploration and Production segment s Canadian oil and gas assets under the full cost method of accounting using natural gas pricing at June 30, 2006 and September 30, 2006;

An $11.2 million benefit to earnings in the Exploration and Production segment ($6.1 million in continuing operations and $5.1 million in discontinued operations) related to income tax adjustments recognized during 2006; and

A $2.6 million benefit to earnings in the Utility segment related to the correction of Distribution Corporation s calculation of the symmetrical sharing component of New York s gas adjustment rate.

Additional discussion of earnings in each of the business segments can be found in the business segment information that follows.

**Earnings (Loss) by Segment**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| Utility | $ 61,472 | $ 50,886 | $ 49,815 |
| Pipeline and Storage | 54,148 | 56,386 | 55,633 |
| Exploration and Production | 146,612 | 74,889 | 67,494 |
| Energy Marketing | 5,889 | 7,663 | 5,798 |
| Timber | 107 | 3,728 | 5,704 |
| Total Reported Segments | 268,228 | 193,552 | 184,444 |
| All Other | 5,672 | 2,564 | 359 |
| Corporate | (5,172) | 5,559 | (189) |
| Total Earnings from Continuing Operations | 268,728 | 201,675 | 184,614 |
| Earnings (Loss) from Discontinued Operations | | 135,780 | (46,523) |
| Total Consolidated | $ 268,728 | $ 337,455 | $ 138,091 |

**UTILITY**

**Revenues**

**Utility Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |

| | | | |
|---|---|---|---|
| Retail Revenues: | | | |
| Residential | $ 876,677 | $ 848,693 | $ 993,928 |
| Commercial | 135,361 | 136,863 | 166,779 |
| Industrial | 7,419 | 8,271 | 13,484 |
| | 1,019,457 | 993,827 | 1,174,191 |
| Off-System Sales | 58,225 | 9,751 | |
| Transportation | 113,901 | 102,534 | 92,569 |
| Other | 18,686 | 14,612 | 14,003 |
| | $ 1,210,269 | $ 1,120,724 | $ 1,280,763 |

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**Utility Throughput million cubic feet (MMcf)**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Retail Sales: | | | |
| Residential | 57,463 | 60,236 | 59,443 |
| Commercial | 9,769 | 10,713 | 10,681 |
| Industrial | 552 | 727 | 985 |
| | 67,784 | 71,676 | 71,109 |
| Off-System Sales | 5,686 | 1,355 | |
| Transportation | 64,267 | 62,240 | 57,950 |
| | 137,737 | 135,271 | 129,059 |

**Degree Days**

| | | | | Percent (Warmer) Colder Than | |
|---|---|---|---|---|---|
| **Year Ended September 30** | | **Normal** | **Actual** | **Normal** | **Prior Year** |
| 2008: | Buffalo | 6,729 | 6,277 | (6.7)% | 0.1% |
| | Erie | 6,277 | 5,779 | (7.9)% | (3.8)% |
| 2007: | Buffalo | 6,692 | 6,271 | (6.3)% | 5.1% |
| | Erie | 6,243 | 6,007 | (3.8)% | 5.6% |
| 2006: | Buffalo | 6,692 | 5,968 | (10.8)% | (9.4)% |
| | Erie | 6,243 | 5,688 | (8.9)% | (8.9)% |

**2008 Compared with 2007**

Operating revenues for the Utility segment increased $89.5 million in 2008 compared with 2007. This increase largely resulted from a $48.5 million increase in off-system sales revenue (see discussion below), a $25.6 million increase in retail gas sales revenues, an $11.3 million increase in transportation revenues, and a $4.1 million increase in other operating revenues.

The increase in retail gas sales revenues for the Utility segment was largely a function of the recovery of higher gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues), which more than offset the revenue impact of lower retail sales volumes, as shown in the table above. See further discussion of purchased gas below under the heading Purchased Gas. This change was also affected by a base rate increase in the Pennsylvania jurisdiction (effective January 2007) that increased operating revenues by $4.0 million for 2008. The increase is included within both retail and transportation revenues in the table above.

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. This rate design change resulted in lower retail and transportation revenues (exclusive of the impact of higher gas costs) during the winter months compared to the prior year and higher retail and transportation revenues in the spring and summer months compared to the prior year. On a cumulative basis for 2008, the impact of this rate order has been to lower operating revenues by $1.4 million. It is expected that there will be an increase in retail and transportation revenue in the first quarter of 2009 compared to the prior year as a result of the rate design change. The increase in transportation revenues was also due to a 2.0 Bcf increase in transportation throughput, largely the result of the migration of customers from retail sales to transportation service.

As reported in 2006, on November 17, 2006 the U.S. Court of Appeals vacated and remanded the FERC s Order No. 2004 regarding affiliate standards of conduct, with respect to natural gas pipelines. The Court s

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decision became effective on January 5, 2007, and on January 9, 2007, the FERC issued Order No. 690, its Interim Rule, designed to respond to the Court s decision. In Order No. 690, as clarified by the FERC on March 21, 2007, the FERC readopted, on an interim basis, certain provisions that existed prior to the issuance of Order No. 2004 that had made it possible for the Utility segment to engage in certain off-system sales without triggering the adverse consequences that would otherwise arise under the Order No. 2004 standards of conduct. As a result, the Utility segment resumed engaging in off-system sales on non-affiliated pipelines as of May 2007, resulting in total off-system sales revenues of $58.2 million and $9.8 million for 2008 and 2007, 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 2008 and 2007.

The increase in other operating revenues of $4.1 million is largely related to amounts recorded 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. The impact of that increase in other operating revenues was offset by an equal amount of operation and maintenance expense (thus there is no earnings impact).

**2007 Compared with 2006**

Operating revenues for the Utility segment decreased $160.0 million in 2007 compared with 2006. This decrease largely resulted from a $180.4 million decrease in retail gas sales revenues. This decrease was partially offset by a $10.0 million increase in transportation revenues and a $9.8 million increase in off-system sales revenues.

The decrease in retail gas sales revenues for the Utility segment was largely a function of the recovery of lower gas costs (gas costs are recovered dollar for dollar in revenues), which more than offset the revenue impact of higher retail sales volumes, as shown in the table above. See further discussion of purchased gas below under the heading Purchased Gas. This decrease was offset slightly by a base rate increase in the Pennsylvania jurisdiction, effective January 2007, which increased operating revenues by $8.5 million for 2007. The increase is included within both retail and transportation revenues in the table above.

The increase in transportation revenues was primarily due to a 4.3 Bcf increase in transportation throughput, largely due to the migration of retail sales customers to transportation service. The corresponding $10.0 million increase in transportation revenues would have been greater if not for a $3.9 million out-of-period adjustment recorded in the first quarter of 2006 to correct Distribution Corporation s calculation of the symmetrical sharing component of New York s gas adjustment rate.

The increase in off-system sales revenue is due to the resumption of off-system sales in May 2007 pursuant to FERC authorization, as discussed above.

**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.

Currently, Distribution Corporation has contracted for long-term firm transportation capacity with Supply Corporation 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 three 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 $11.23 per Mcf in 2008, an increase of 12% from the average cost of $10.04 per Mcf in 2007. The average cost of purchased gas in 2007 was 17% lower than the average cost of $12.07 per Mcf in 2006. Additional discussion of the Utility segment s gas purchases appears under the heading Sources and Availability of Raw Materials in Item 1.

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## Earnings

### 2008 Compared with 2007

The Utility segment s earnings in 2008 were $61.5 million, an increase of $10.6 million when compared with earnings of $50.9 million in 2007.

In the New York jurisdiction, earnings increased by $6.9 million. This was primarily due to a $3.6 million overall decrease in operating expenses (mostly other post-retirement benefits and bad debt expense), higher non-cash interest income on a pension-related regulatory asset ($2.6 million), a decrease in property, franchise, and other taxes ($0.9 million), a decrease in depreciation expense ($0.8 million), lower income tax expense ($0.7 million), lower interest expense ($0.2 million), and increased usage per account ($0.5 million). The impact of these items more than offset lower base rates due to the rate design change described above ($0.9 million), and routine regulatory adjustments that reduced earnings by $1.8 million.

In the Pennsylvania jurisdiction, earnings increased by $3.7 million. This was primarily due to a base rate increase ($2.6 million) that became effective January 2007, an increase in normalized usage ($1.3 million), a decrease in bad debt expense ($1.1 million), and a decrease in property, franchise, and other taxes ($0.3 million). Warmer weather ($1.6 million) partially offset these increases.

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. In 2008 and 2007, the WNC preserved earnings of approximately $2.5 million and $2.3 million, respectively, as the weather was warmer than normal.

### 2007 Compared with 2006

The Utility segment s earnings in 2007 were $50.9 million, an increase of $1.1 million when compared with earnings of $49.8 million in 2006.

In the New York jurisdiction, earnings decreased by $6.2 million. This was primarily due to lower interest income ($4.5 million). The New York division s current rate agreement with the NYPSC allows the Company to accrue interest on a pension-related regulatory asset. The amount of interest that can be accrued is reduced as the funded status of the pension plan improves. The fair market value of the pension plan assets exceeded the accumulated benefit obligation at September 30, 2007 resulting in a significant reduction in the interest accrual on this regulatory asset. The out-of-period symmetrical sharing adjustment discussed above ($2.6 million), higher bad debt and other operating costs ($0.8 million), higher property taxes ($0.6 million), and higher interest expense ($0.5 million) also contributed to this decrease. The positive impact associated with a lower effective tax rate ($1.9 million) and increased usage per account ($1.9 million) partially offset the overall decrease.

In the Pennsylvania jurisdiction, earnings increased by $7.3 million. This was primarily due to a base rate increase ($5.5 million) that became effective January 2007, colder weather ($2.5 million), and the positive impact associated with a lower effective tax rate ($1.1 million). Higher intercompany and other interest expense ($0.8 million), coupled with a decrease in normalized usage ($0.3 million), partially offset these increases.

The impact of weather on the Utility segment s New York rate jurisdiction is tempered by a 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. In 2007 and 2006, the WNC preserved earnings of approximately $2.3 million and $6.2 million, respectively, as the weather was warmer than normal.

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**PIPELINE AND STORAGE**

**Revenues**

**Pipeline and Storage Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| Firm Transportation | $ 122,321 | $ 118,771 | $ 118,551 |
| Interruptible Transportation | 4,330 | 4,161 | 4,858 |
| | 126,651 | 122,932 | 123,409 |
| Firm Storage Service | 67,020 | 66,966 | 66,718 |
| Interruptible Storage Service | 14 | 169 | 39 |
| | 67,034 | 67,135 | 66,757 |
| Other | 22,871 | 21,899 | 24,186 |
| | $ 216,556 | $ 211,966 | $ 214,352 |

**Pipeline and Storage Throughput (MMcf)**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Firm Transportation | 353,173 | 351,113 | 363,379 |
| Interruptible Transportation | 5,197 | 4,975 | 11,609 |
| | 358,370 | 356,088 | 374,988 |

**2008 Compared with 2007**

Operating revenues for the Pipeline and Storage segment increased $4.6 million in 2008 as compared with 2007. The majority of the increase was the result of increased transportation revenues ($3.7 million) due to the fact that the Pipeline & Storage segment was able to renew existing contracts at higher rates due to favorable market conditions for transportation service associated with storage. In addition, there were increased efficiency gas revenues ($0.8 million) reported as part of other revenues in the table above. The majority of this increase was due to higher gas prices in the current year.

**2007 Compared with 2006**

Operating revenues for the Pipeline and Storage segment decreased $2.4 million in 2007 as compared with 2006, which was due mostly to a decrease in other revenues ($2.3 million). The decrease in other revenues is primarily due to a $4.2 million decrease in efficiency gas revenues. This decrease was due to the Company s recent settlement with the FERC, which decreased efficiency gas retainage allowances. Offsetting this decrease, there was a $1.4 million increase in other revenues attributable to the lease termination fee adjustment in 2006 (an intercompany transaction) for the Company s former headquarters, which did not recur in 2007. While Supply Corporation s transportation volumes decreased during the year, volume fluctuations generally do not have a significant impact on revenues as a result of Supply Corporation s straight-fixed variable rate design.

**Earnings**

**2008 Compared with 2007**

The Pipeline and Storage segment s earnings in 2008 were $54.1 million, a decrease of $2.2 million when compared with earnings of $56.4 million in 2007. The main factors contributing to this decrease were higher operation and maintenance expenses ($6.1 million), primarily caused by the non-recurrence in 2008 of a reversal of a reserve for preliminary survey costs related to the Empire Connector project during 2007

($4.8 million). In addition, there was a $1.9 million positive earnings impact during 2007 associated with the discontinuance of hedge accounting for Empire s interest rate collar that did not recur during 2008, and the Pipeline and Storage segment experienced higher interest costs ($1.5 million). These earnings decreases were offset by the earnings impact associated with higher transportation revenues ($2.4 million), an increase in the allowance for funds used during construction ($4.2 million) and the earnings impact associated with higher efficiency gas revenues ($0.5 million).

**2007 Compared with 2006**

The Pipeline and Storage segment s earnings in 2007 were $56.4 million, an increase of $0.8 million when compared with earnings of $55.6 million in 2006. The main factor contributing to this increase was the reversal of a reserve for preliminary survey costs ($4.8 million) related to the Empire Connector project. Based on the signing of a service agreement with KeySpan Gas East Corporation during the quarter ended June 30, 2007, management determined that it was probable that the project would go forward and that such preliminary survey costs were properly capitalizable in accordance with the FERC s Uniform System of Accounts and SFAS 71. In addition, there was a $2.5 million increase in earnings associated with the decrease in depreciation expense as a result of the most recent settlement with the FERC, which reduced depreciation rates. There was also a $1.9 million positive earnings impact associated with the discontinuance of hedge accounting for Empire s interest rate collar. On December 8, 2006, Empire repaid $22.8 million of secured debt. The interest costs of this secured debt were hedged by the interest rate collar. Since the hedged transaction was settled and there will be no future cash flows associated with the secured debt, the unrealized gain in accumulated other comprehensive income associated with the interest rate collar was reclassified to the income statement. These earnings increases were offset by higher interest expense ($3.2 million), the earnings impact associated with lower efficiency gas revenues ($2.7 million), a $1.5 million increase in operating costs (primarily post-retirement benefit costs), and the earnings decrease associated with a higher effective tax rate ($0.9 million).

**EXPLORATION AND PRODUCTION**

**Revenues**

**Exploration and Production Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007<br>(Thousands) | 2006 |
| Gas (after Hedging) from Continuing Operations | $ 202,153 | $ 143,785 | $ 126,969 |
| Oil (after Hedging) from Continuing Operations | 250,965 | 167,627 | 134,307 |
| Gas Processing Plant from Continuing Operations | 49,090 | 37,528 | 42,252 |
| Other from Continuing Operations | (944) | 1,147 | 3,072 |
| Intrasegment Elimination from Continuing Operations(1) | (34,504) | (26,050) | (31,704) |
| Operating Revenues from Continuing Operations | $ 466,760 | $ 324,037 | $ 274,896 |
| Operating Revenues from Canada Discontinued Operations | $ | $ 50,495 | $ 71,984 |

(1)

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

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**Production Volumes**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| **Gas Production** *(MMcf)* | | | |
| Gulf Coast | 11,033 | 10,356 | 9,110 |
| West Coast | 4,039 | 3,929 | 3,880 |
| Appalachia | 7,269 | 5,555 | 5,108 |
| Total Production from Continuing Operations | 22,341 | 19,840 | 18,098 |
| Canada Discontinued Operations | | 6,426 | 7,673 |
| Total Production | 22,341 | 26,266 | 25,771 |
| **Oil Production** *(Mbbl)* | | | |
| Gulf Coast | 505 | 717 | 685 |
| West Coast | 2,460 | 2,403 | 2,582 |
| Appalachia | 105 | 124 | 69 |
| Total Production from Continuing Operations | 3,070 | 3,244 | 3,336 |
| Canada Discontinued Operations | | 206 | 272 |
| Total Production | 3,070 | 3,450 | 3,608 |

**Average Prices**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| **Average Gas Price/Mcf** | | | |
| Gulf Coast | $ 10.03 | $ 6.58 | $ 8.01 |
| West Coast | $ 8.71 | $ 6.54 | $ 7.93 |
| Appalachia | $ 9.73 | $ 7.48 | $ 9.53 |
| Weighted Average for Continuing Operations | $ 9.70 | $ 6.82 | $ 8.42 |
| Weighted Average After Hedging for Continuing Operations(1) | $ 9.05 | $ 7.25 | $ 7.02 |
| Canada Discontinued Operations | $ | $ 6.09 | $ 7.14 |
| **Average Oil Price/Barrel (bbl)** | | | |
| Gulf Coast | $ 107.27 | $ 63.04 | $ 64.10 |
| West Coast(2) | $ 98.17 | $ 56.86 | $ 56.80 |
| Appalachia | $ 97.40 | $ 62.26 | $ 65.28 |
| Weighted Average for Continuing Operations | $ 99.64 | $ 58.43 | $ 58.47 |
| Weighted Average After Hedging for Continuing Operations(1) | $ 81.75 | $ 51.68 | $ 40.26 |
| Canada Discontinued Operations | $ | $ 50.06 | $ 51.40 |

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

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

**2008 Compared with 2007**

Operating revenues from continuing operations for the Exploration and Production segment increased $142.7 million in 2008 as compared with 2007. Oil production revenue after hedging from continuing operations increased $83.3 million due primarily to a $30.07 per barrel increase in weighted average prices after hedging, which more than offset a decrease in oil production of 174,000 barrels. Gas production revenue after hedging from continuing operations increased $58.4 million due to a $1.80 per Mcf increase in weighted average prices after hedging and a 2,501 MMcf increase in production. The increase in gas production from continuing operations occurred primarily in the Appalachian region (1,714 MMcf), consistent with increased drilling activity in the region. The Gulf Coast region also contributed significantly to the increase in natural gas production from continuing operations (677 MMcf). Production from new fields in 2008 (primarily in the High Island area) outpaced declines in production from some existing fields, period to period. Production in this region would have been higher if not for the hurricane activity during the month of September 2008. As a result of hurricanes Edouard, Gustav and Ike, production was shut in for much of the month of September, resulting in estimated lost production of approximately 804 MMcf of natural gas and 45 Mbbl of oil. While Seneca s properties sustained only superficial damage from the hurricanes, approximately 50% of the pre-hurricane production remains shut-in due to repair work on third party pipelines and onshore processing facilities. The majority of this production is anticipated to return by December 1, 2008.

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.

**2007 Compared with 2006**

Operating revenues from continuing operations for the Exploration and Production segment increased $49.1 million in 2007 as compared with 2006. Oil production revenue after hedging increased $33.3 million due primarily to an $11.42 per barrel increase in weighted average prices after hedging, which more than offset a slight decrease in oil production of 92,000 barrels. Gas production revenue after hedging increased $16.8 million in 2007 as compared with 2006. An increase in gas production of 1,742 MMcf and an increase in weighted average prices after hedging of $0.23 per Mcf both contributed to the increase. The increase in gas production occurred primarily in the Gulf Coast region (1,246 MMcf). During the quarter ended December 31, 2005, Seneca experienced significant production delays due largely to the impact of hurricane damage to pipeline infrastructure in the Gulf of Mexico. Seneca had substantially all of its pre-hurricane Gulf of Mexico production back on line at the beginning of fiscal 2007. Production also increased in this segment s Appalachian region (447 MMcf), primarily due to increased drilling in this region during 2007, as highlighted in Item 2 under Exploration and Production Activities.

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**

**2008 Compared with 2007**

The Exploration and Production segment s earnings from continuing operations for 2008 were $146.6 million, an increase of $71.7 million when compared with earnings from continuing operations of $74.9 million for 2007. Higher crude oil prices, higher natural gas prices and higher natural gas production increased earnings by $60.0 million, $26.2 million and $11.8 million, respectively, while lower crude oil production decreased earnings by $5.8 million. Higher lease operating costs ($11.9 million), higher depletion expense ($9.1 million), higher income tax expense ($1.1 million) and higher general and administrative and other operating expenses ($6.2 million) also negatively impacted earnings. Lower interest expense and higher interest income of $6.6 million and $0.7 million, respectively, partially offset these decreases to earnings. The increase in lease operating costs resulted from the start-up of production at the High Island 24L field in October 2007, higher steaming costs in California, and an increase in costs associated with a higher number of producing properties in Appalachia. The increase in depletion expense was caused by higher production and an increase in the depletable base. The increase in general and administrative and other operating expenses resulted from an increase in staffing and associated costs for the growing Appalachia division combined with the recognition of actual plugging costs in excess of previously accrued amounts.

**2007 Compared with 2006**

The Exploration and Production segment s earnings from continuing operations for 2007 were $74.9 million, an increase of $7.4 million when compared with earnings from continuing operations of $67.5 million for 2006. Higher crude oil prices, higher natural gas production and higher natural gas prices increased earnings by $24.1 million, $7.9 million and $3.0 million, respectively. These increases were partly offset by the non-recurrence of $6.1 million of tax benefits recognized during 2006, as well as by higher depletion expense and higher lease operating expense of $7.2 million and $4.6 million, respectively. Slightly lower crude oil production and higher general and administrative expenses also decreased earnings by $2.4 million and $0.6 million, respectively. Earnings were also negatively impacted by higher income tax expense ($6.3 million).

**ENERGY MARKETING**

**Revenues**

**Energy Marketing Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| Natural Gas (after Hedging) | $ 551,243 | $ 413,405 | $ 496,769 |
| Other | (11) | 207 | 300 |
| | $ 551,232 | $ 413,612 | $ 497,069 |

**Energy Marketing Volumes**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Natural Gas (MMcf) | 56,120 | 50,775 | 45,270 |

**2008 Compared with 2007**

Operating revenues for the Energy Marketing segment increased $137.6 million in 2008 as compared with 2007. The increase is primarily due to higher gas sales revenue, as a result of an increase in the price of natural gas that was recovered through revenues, coupled with an increase in volumes. The increase in volumes is primarily attributable to an increase in volumes sold to low-margin wholesale customers, as well as an increase in the number of commercial and industrial customers served by the Energy Marketing segment. The increase in volumes also reflects certain sales transactions undertaken to offset certain basis risks that the Energy Marketing segment was exposed to under certain commodity purchase contracts. The offsetting purchase and sale transactions had the effect of increasing revenue and volumes sold with minimal impact to earnings.

**2007 Compared with 2006**

Operating revenues for the Energy Marketing segment decreased $83.5 million in 2007 as compared with 2006. The decrease primarily reflects lower gas sales revenue due to a decrease in natural gas commodity prices for the period that were recovered through revenues, offset in part by an increase in volumes. The increase in volumes was due to the addition of certain large, low-margin commercial and industrial customers, an increase in sales to wholesale customers, and colder weather.

**Earnings**

**2008 Compared with 2007**

The Energy Marketing segment s earnings in 2008 were $5.9 million, a decrease of $1.8 million when compared with earnings of $7.7 million in 2007. Higher operating costs of $1.1 million (primarily due to an increase in bad debt expense) coupled with lower margins of $1.1 million are primarily responsible for the decrease in earnings. A major factor in the margin decrease is the non-recurrence of a purchased gas expense

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adjustment recorded during the quarter ended March 31, 2007. During that quarter, the Energy Marketing segment reversed an accrual for $2.3 million of purchased gas expense due to a resolution of a contingency. The increase in volumes noted above, the profitable sale of certain gas held as inventory, and the marketing flexibility that the Energy Marketing segment derives from its contracts for significant storage capacity partially offset the margin decrease associated with the purchased gas adjustment.

**2007 Compared with 2006**

The Energy Marketing segment s earnings in 2007 were $7.7 million, an increase of $1.9 million when compared with earnings of $5.8 million in 2006. Higher margins of $2.3 million are responsible for the increase in earnings. The increase in margin is mainly the result of a $2.3 million reversal of an accrual for purchased gas expense related to the resolution of a contingency during 2007. While volumes increased, as noted above, much of this increase in volume is related to sales to low margin customers.

**TIMBER**

**Revenues**

**Timber Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| Log Sales | $ 19,989 | $ 21,927 | $ 23,077 |
| Green Lumber Sales | 4,864 | 5,097 | 7,123 |
| Kiln-Dried Lumber Sales | 22,914 | 27,908 | 32,809 |
| Other | 1,749 | 3,965 | 2,020 |
| | $ 49,516 | $ 58,897 | $ 65,029 |

**Timber Board Feet**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| Log Sales | 9,272 | 8,660 | 9,527 |
| Green Lumber Sales | 9,747 | 9,358 | 10,454 |
| Kiln-Dried Lumber Sales | 13,425 | 14,778 | 16,862 |
| | 32,444 | 32,796 | 36,843 |

**2008 Compared with 2007**

Operating revenues for the Timber segment decreased $9.4 million in 2008 as compared with 2007. Unfavorable market conditions for cherry logs and lumber combined with wet weather conditions that hampered harvesting were the main factors causing the decrease. The decrease consisted of a $5.0 million decline in kiln-dried lumber sales. The decrease in kiln-dried lumber sales was due to both a decline in the market price of kiln-dried lumber as well as a 1,353,000 board feet decline in kiln-dried lumber sales volumes (primarily kiln-dried cherry lumber sales volumes). Log sales also decreased $1.9 million primarily due to a decline in cherry veneer log sales volumes of 328,000 board feet. Cherry veneer logs are more valuable and sell at higher prices than other species and have the largest impact on overall log sales revenue. In addition, in 2007 the Timber segment sold 3.1 million board feet of timber rights and recorded a gain of $1.6 million in other revenues. This event did not recur in 2008.

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**2007 Compared with 2006**

Operating revenues for the Timber segment decreased $6.1 million in 2007 as compared with 2006. This decrease is attributed to unfavorable weather conditions primarily during the fall of 2006 and the spring of 2007 that greatly limited the harvesting of logs. These conditions consisted of warm, wet weather that made it difficult to bring logging trucks into the forests. Weather conditions were significantly more favorable throughout fiscal 2006. These unfavorable conditions for harvesting resulted in a decline in log sales of $1.2 million or 867,000 board feet. There was also a decline in both green lumber and kiln-dried lumber sales of $2.0 million and $4.9 million, respectively, primarily because there were fewer logs available for processing. Declines in market prices for the cherry and maple species also contributed to the decrease in green lumber and kiln-dried lumber sales. Additionally, the processing of a greater amount of lumber species other than cherry (due to the mix of species on the areas being harvested) contributed to the decline in kiln-dried lumber sales since lumber species other than cherry are sold at a lower price than kiln-dried cherry lumber. Offsetting the decreases discussed above, other revenues increased $1.9 million largely due to the sale of 3.1 million board feet of timber rights ($1.6 million).

**Earnings**

**2008 Compared with 2007**

The Timber segment earnings in 2008 were $0.1 million, a decrease of $3.6 million when compared with earnings of $3.7 million in 2007. The decrease was primarily due to lower margins from lumber, log and timber rights sales ($4.2 million) as a result of the decline in revenues noted above. This decrease was partially offset by the earnings benefit associated with a lower effective tax rate ($0.8 million).

**2007 Compared with 2006**

The Timber segment earnings in 2007 were $3.7 million, a decrease of $2.0 million when compared with earnings of $5.7 million in 2006. The decrease was primarily due to lower margins from lumber and log sales ($2.5 million) as a result of the decline in revenues noted above, as well as higher general and administrative expenses of $0.3 million. Partially offsetting this decrease was a decline in depletion expense of $1.2 million. The decrease in depletion expense reflects the cutting of more low cost or no cost basis timber from Company owned land as well as the overall decrease in logs harvested.

**ALL OTHER AND CORPORATE OPERATIONS**

All Other and Corporate operations primarily includes the operations of Horizon LFG, Horizon Power, former International segment activity and corporate operations. Horizon LFG owns and operates short-distance landfill gas pipeline companies. 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. ESNE generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania.

**Earnings**

**2008 Compared with 2007**

All Other and Corporate operations had earnings of $0.5 million in 2008, a decrease of $7.6 million compared with earnings of $8.1 million for 2007. The positive earnings impact of higher income from unconsolidated subsidiaries ($0.9 million) and a gain on the sale of a turbine by Horizon Power ($0.6 million) were more than offset by higher operating costs ($6.1 million), higher income tax expense ($1.7 million) and lower interest income ($1.3 million). The increase in operating costs is primarily the result of the proxy contest with New Mountain Vantage GP, L.L.C.

**2007 Compared with 2006**

All Other and Corporate operations had earnings of $8.1 million in 2007, an increase of $7.9 million compared with earnings of $0.2 million for 2006. This improvement was largely due to an increase in interest income of $4.1 million (primarily intercompany interest). In the All Other category, Horizon LFG s earnings benefited from higher margins of $1.0 million in 2007 as compared to 2006, and Horizon Power s income from unconsolidated subsidiaries increased $0.9 million, also contributing to the increase in earnings. The Corporate and All Other categories also had an earnings benefit associated with lower income tax expense ($2.0 million).

**INTEREST INCOME**

Interest income was $9.3 million higher in 2008 as compared to 2007. The main reason for this increase was a $4.0 million increase in interest income on a pension-related regulatory asset in the Utility segment s New York jurisdiction. The Exploration and Production segment also contributed $3.8 million to this increase as a result of the investment of cash proceeds from the sale of SECI in August 2007.

Interest income was $7.9 million lower in 2007 as compared to 2006. As discussed in the Utility earnings section above, the main reason for this decrease was a $7.4 million decrease in interest income on a pension-related regulatory asset in the Utility segment s New York jurisdiction.

**OTHER INCOME**

Other income was $2.4 million higher in 2008 as compared to 2007. This increase is attributed to the increase in the allowance for funds used during construction, in the Pipeline and Storage segment, associated with the Empire Connector project of $4.2 million. This increase was partially offset by the non-recurrence of a death benefit gain on life insurance proceeds of $1.9 million recognized in the Corporate category in 2007.

Other income was $2.1 million higher in 2007 as compared to 2006. The increase is attributed to a death benefit gain on life insurance proceeds of $1.9 million recognized in the Corporate category.

**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 $1.7 million in 2008 as compared to 2007. The increase in 2008 was primarily the result of a higher average amount of long-term debt outstanding. In April 2008, the Company issued $300 million of 6.5% senior, unsecured notes due in April 2018. This increase was partially offset by the repayment of $200 million of 6.303% medium-term notes that matured on May 27, 2008.

Interest on long-term debt decreased $4.2 million in 2007 as compared to 2006. The decrease in 2007 was primarily the result of a lower average amount of long-term debt outstanding. In addition, the Company recognized a $1.9 million benefit to interest expense as a result of the discontinuance of hedge accounting for Empire s interest rate collar, as discussed above under Pipeline and Storage. The underlying long-term debt associated with this interest rate collar was repaid in December 2006 and the unrealized gain recorded in accumulated other comprehensive income associated with the interest rate collar was reclassified to interest expense during the quarter ended December 31, 2006.

Other interest charges decreased $2.2 million in 2008 compared to 2007. Other interest charges did not change significantly in 2007 as compared to 2006. The decrease in 2008 was primarily caused by a $1.7 million increase in the allowance for borrowed funds used during construction related to the Empire Connector project.

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## 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 | | |
|---|---|---|---|
| | 2008 | 2007 (Millions) | 2006 |
| Provided by Operating Activities | $ 482.8 | $ 394.2 | $ 471.4 |
| Capital Expenditures | (397.7) | (276.7) | (294.2) |
| Investment in Partnership | | (3.3) | |
| Net Proceeds from Sale of Foreign Subsidiaries | | 232.1 | |
| Cash Held in Escrow | 58.4 | (58.2) | |
| Net Proceeds from Sale of Oil and Gas Producing Properties | 5.9 | 5.1 | |
| Other Investing Activities | 4.4 | (0.8) | (3.2) |
| Reduction of Long-Term Debt | (200.0) | (119.6) | (9.8) |
| Net Proceeds from Issuance of Long-Term Debt | 296.6 | | |
| Issuance of Common Stock | 17.4 | 17.5 | 23.3 |
| Dividends Paid on Common Stock | (103.7) | (100.6) | (98.2) |
| Excess Tax Benefits Associated with Stock- Based Compensation Awards | 16.3 | 13.7 | 6.5 |
| Shares Repurchased under Repurchase Plan | (237.0) | (48.1) | (85.2) |
| Effect of Exchange Rates on Cash | | (0.1) | 1.4 |
| Net Increase (Decrease) in Cash and Temporary Cash Investments | $ (56.6) | $ 55.2 | $ 12.0 |

**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 Supply Corporation s straight fixed-variable rate design.

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 $482.8 million in 2008, an increase of $88.6 million compared with the $394.2 million provided by operating activities in 2007. The increase is partially due to lower working capital requirements in the Utility segment. In the Exploration and Production segment, cash provided by operations increased due to higher commodity prices, partially offset by the decrease in cash provided by operations that resulted from the sale of SECI in August 2007. Offsetting these increases were higher working capital requirements in the Energy Marketing segment.

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## INVESTING CASH FLOW

### Expenditures for Long-Lived Assets

The Company s expenditures for long-lived assets totaled $414.5 million in 2008. The table below presents these expenditures:

| | Year Ended September 30, 2008 Total Expenditures For Long-Lived Assets (Millions) |
|---|---|
| Utility | $ 57.5 |
| Pipeline and Storage(1) | 165.5 |
| Exploration and Production | 192.2 |
| Timber | 1.4 |
| All Other and Corporate | 0.3 |
| Eliminations(2) | (2.4) |
| | $ 414.5 |

(1) Amount includes $16.8 million of accrued capital expenditures related to the Empire Connector project. This amount has been excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represents a non-cash investing activity at that date.

(2) 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.

### Utility

The majority of the Utility capital expenditures 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 were related to the Empire Connector project costs, which is discussed below under Estimated Capital Expenditures, as well as for additions, improvements and replacements to this segment s transmission and gas storage systems.

### Exploration and Production

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.

**Timber**

The majority of the Timber segment capital expenditures 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.

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**All Other and Corporate**

In March 2008, Horizon Power sold a gas-powered turbine 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 | | |
|---|---|---|---|
| | 2009 | 2010 (Millions) | 2011 |
| Utility | $ 58.0 | $ 60.0 | $ 56.0 |
| Pipeline and Storage | 73.0 | 76.0 | 46.0 |
| Exploration and Production(1) | 285.0 | 227.0 | 244.0 |
| Timber | 1.0 | 1.0 | 1.0 |
| | $ 417.0 | $ 364.0 | $ 347.0 |

(1) Includes estimated expenditures for the years ended September 30, 2009, 2010 and 2011 of approximately $48 million, $42 million and $18 million, respectively, to develop proved undeveloped reserves.

Estimated capital expenditures for the Utility segment in 2009 will be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment.

Estimated capital expenditures for the Pipeline and Storage segment in 2009 will be concentrated on the completion of the Empire Connector project as discussed below, the replacement of transmission and storage lines, the reconditioning of storage wells and improvements of compressor stations.

The Company continues to explore various opportunities to expand its capabilities to transport gas to the East Coast, either through the Supply Corporation or Empire systems or in partnership with others. Construction of the Empire Connector, a pipeline designed to transport up to approximately 250 MDth of natural gas per day that will connect the Empire Pipeline with the Millennium Pipeline, began in September 2007. The Empire Connector is anticipated to be ready to commence service in December 2008, on or before the in-service date of the Millennium Pipeline. Refer to the Rate and Regulatory Matters section that follows for further discussion of this matter. The total cost to the Company of the Empire Connector project is estimated at $187 million, after giving effect to sales tax exemptions worth approximately $3.7 million. As of September 30, 2008, the Company had incurred approximately $164.7 million in costs related to this project. Of this amount, $145.0 million, $13.7 million and $2.0 million were incurred during the years ended September 30, 2008, 2007 and 2006, respectively. All project costs incurred as of September 30, 2008 have been capitalized as Construction Work in Progress. The Company anticipates financing the remaining cost of this project with cash from operations.

In light of the rapidly 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 recently completed an Open

Season for its Appalachian Lateral ( AppLat ) pipeline project. The AppLat is expected to be routed through areas in Pennsylvania where producers are actively drilling and are seeking market access for their newly discovered reserves. The AppLat will complement Supply s original West to East ( W2E ) project, which was designed to transport Rockies gas supply from Clarington to the Ellisburg/Leidy/Corning area and includes the Tuscarora-to-Corning facilities previously referred to as the Tuscarora Extension. The AppLat will transport gas supply from Pennsylvania s producing area to the Overbeck area of Supply Corporation s existing system, where the facilities associated with the W2E project will move the gas to eastern market points, including Leidy, and to interconnections with Millennium and Empire at Corning.

In conjunction with the W2E and AppLat transportation projects, Supply Corporation has plans to develop new storage capacity by pursuing expansion of certain of its existing storage facilities. The expansion of these

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fields, which Supply Corporation is marketing through a recently completed Open Season concurrent with its AppLat Open Season, could provide approximately 8.5 MMDth of incremental storage capacity with incremental withdrawal deliverability of up to 121 MDth of natural gas per day, with service commencing as early as 2011. Supply Corporation expects that the availability of this incremental storage capacity will complement the W2E and AppLat pipeline projects and help meet the demand for storage created by the prospective increased flow of Appalachian and Rockies gas supply into the western Pennsylvania area, although traditional gas supplies will also be able to take advantage of this incremental storage capacity.

The timeline associated with Supply Corporation s pipeline and storage projects depends on market development. The capital cost of the AppLat/W2E project is estimated to be approximately $800 million, and is expected to be financed by a combination of debt and equity. As of September 30, 2008, $0.2 million has been spent to study the W2E and AppLat projects, and approximately $0.6 million has been spent to study the storage expansion project. Costs associated with these projects have been included in preliminary survey and investigation charges and have been fully reserved for at September 30, 2008. Supply Corporation has not yet filed an application with the FERC for the authority to build either pipeline project or the storage expansion.

Estimated capital expenditures in 2009 for the Exploration and Production segment include approximately $35.0 million for the Gulf Coast region, substantially all of which is for the off-shore program in the Gulf of Mexico, $53.6 million for the West Coast region and $196.3 million for the Appalachian region.

Estimated capital expenditures in 2009 in the Timber segment will be concentrated on the purchase of new equipment, vehicles and improvements to facilities for this segment s lumber yard, sawmill and kiln operations.

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, timber or 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, 2008. 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 $420.0 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 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 that extends through September 30, 2010.

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, 2010. At September 30, 2008, the Company s debt to capitalization ratio (as calculated under the facility) was .41. The constraints specified in the committed credit facility would permit an additional $1.88 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company s debt to capitalization ratio would exceed .65. If a downgrade in any of the Company s credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company s existing indenture covenants, at September 30, 2008, 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.

The Company s 1974 indenture, pursuant to which $199.0 million (or 18%) of the Company s long-term debt (as of September 30, 2008) 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 fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2008, the Company had no debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 6.5% at September 30, 2008 and 6.4% at September 30, 2007. Refer to Interest Rate Risk in this Item for a more detailed breakdown of the Company s embedded cost of long-term debt.

In April 2008, the Company issued $300.0 million of 6.50% senior, unsecured notes in a private placement exempt from registration under the Securities Act of 1933. The notes have a term of 10 years, with a maturity date in April 2018. The holders of the notes may require the Company to repurchase their notes in the event of a change in control at a price equal to 101% of the principal amount. In addition, the Company is required to either offer to exchange the notes for substantially similar notes as are registered under the Securities Act of 1933 or, in certain circumstances, register the resale of the notes. The Company used $200.0 million of the proceeds to refund $200.0 million of 6.303% medium-term notes that subsequently matured on May 27, 2008. In November 2008 the Company filed a registration statement with the SEC in connection with the Company s plan to offer to exchange the notes for substantially similar registered notes. The Company will seek to have the SEC declare the registration statement effective as of a date coinciding with or following the date of this report.

In December 2005, the Company s Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may 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. Under this new authorization, the Company repurchased 1,028,981 shares for $46.0 million through September 17, 2008. The Company stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. However, such repurchases may be made in the future if conditions improve. All 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.

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## OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating and capital 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 $32.3 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. The Company s unconsolidated subsidiaries, which are accounted for under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $3.0 million. The Company has guaranteed 50%, or $1.5 million, of these capital lease commitments.

## CONTRACTUAL OBLIGATIONS

The following table summarizes the Company s expected future contractual cash obligations as of September 30, 2008, and the twelve-month periods over which they occur:

| | Payments by Expected Maturity Dates | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 (Millions) | 2013 | Thereafter | Total |
| Long-Term Debt, including interest expense(1) | $ 167.5 | $ 65.0 | $ 252.2 | $ 191.4 | $ 282.3 | $ 565.0 | $ 1,523.4 |
| Operating Lease Obligations | $ 6.0 | $ 4.6 | $ 3.6 | $ 3.2 | $ 2.5 | $ 12.4 | $ 32.3 |
| Capital Lease Obligations | $ 0.5 | $ 0.4 | $ 0.4 | $ 0.2 | $ | $ | $ 1.5 |
| Purchase Obligations: | | | | | | | |
| Gas Purchase Contracts(2) | $ 745.8 | $ 122.3 | $ 14.5 | $ 10.3 | $ 10.3 | $ 83.8 | $ 987.0 |
| Transportation and Storage Contracts | $ 47.4 | $ 45.7 | $ 41.1 | $ 36.7 | $ 11.3 | $ 16.9 | $ 199.1 |
| Empire Connector Project Obligations | $ 13.5 | $ | $ | $ | $ | $ | $ 13.5 |
| Other | $ 12.4 | $ 10.5 | $ 4.2 | $ 4.0 | $ 3.5 | $ 12.6 | $ 47.2 |

(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 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 sheet in accordance with SFAS 133 (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 sheet as a current liability; and (iii) other obligations which are reflected on the consolidated balance sheet. 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 H 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 2008, the Company contributed $16.0 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2009 will be in the range of $15.0 million to $20.0 million. As a result of the recent downturn in the stock markets and general economic conditions, it is likely that the Company will have to fund larger amounts to the Retirement Plan subsequent to 2009 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 2008, the Company contributed $29.1 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 2009 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.

**MARKET RISK SENSITIVE INSTRUMENTS**

**Energy Commodity Price Risk**

The Company, in its Exploration and Production segment, Energy Marketing segment, Pipeline and Storage segment, and All Other category, uses various derivative financial instruments (derivatives), including price swap agreements, no cost collars 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, 2008 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.

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, 2008. At September 30, 2008, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2011.

***Natural Gas Price Swap Agreements***

| | Expected Maturity Dates | | | |
|---|---|---|---|---|
| | **2009** | **2010** | **2011** | **Total** |
| Notional Quantities (Equivalent Bcf) | 11.8 | 3.3 | 0.0(1) | 15.1 |
| Weighted Average Fixed Rate (per Mcf) | $ 9.35 | $ 10.89 | $ 10.55 | $ 9.69 |
| Weighted Average Variable Rate (per Mcf) | $ 8.10 | $ 8.74 | $ 9.30 | $ 8.24 |

(1) The Energy Marketing segment has natural gas swap agreements covering approximately 40,000 Mcf in 2011.

*Crude Oil Price Swap Agreements*

| | Expected Maturity Dates | | | |
|---|---|---|---|---|
| | 2009 | 2010 | 2011 | Total |
| Notional Quantities (Equivalent bbls) | 1,260,000 | 600,000 | 60,000 | 1,920,000 |
| Weighted Average Fixed Rate (per bbl) | $ 83.12 | $ 102.52 | $ 125.25 | $ 90.50 |
| Weighted Average Variable Rate (per bbl) | $ 103.08 | $ 104.17 | $ 105.21 | $ 103.49 |

At September 30, 2008, the Company would have received from its respective counterparties an aggregate of approximately $20.3 million to terminate the natural gas price swap agreements outstanding at that date. The Energy Marketing segment also used natural gas swaps to hedge basis risk on their fixed price purchase commitments. At September 30, 2008, the Company had natural gas basis swap agreements covering 1.4 Bcf at a weighted average fixed rate of $0.47 (per Mcf) and a weighted average variable rate of $0.64 (per Mcf). These natural gas swap agreements are treated as fair value hedges and the Company would have had to pay $0.2 million at September 30, 2008 to terminate the agreements. The Company would have had to pay an aggregate of approximately $0.8 million to its counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2008.

At September 30, 2007, the Company had natural gas price swap agreements covering 13.2 Bcf at a weighted average fixed rate of $8.20 per Mcf. The Company also had crude oil price swap agreements covering 1,485,000 bbls at a weighted average fixed rate of $57.35 per bbl.

The following table discloses the net contract volumes 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, 2008, the Company held no futures contracts with maturity dates extending beyond 2012.

*Futures Contracts*

| | Expected Maturity Dates | | | | |
|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | Total |
| Net Contract Volumes Purchased (Sold) (Equivalent Bcf) | 2.1 | 0.3 | (1) | (1) | 2.4 |
| Weighted Average Contract Price (per Mcf) | $ 10.02 | $ 9.59 | $ 8.05 | $ 8.68 | $ 9.99 |
| Weighted Average Settlement Price (per Mcf) | $ 9.41 | $ 9.85 | $ 7.49 | $ 8.27 | $ 9.43 |

(1) The Energy Marketing segment has purchased 7 and 6 futures contracts (1 contract = 2,500 Dth) for 2011 and 2012, respectively.

At September 30, 2008, the Company would have received $8.7 million to terminate these futures contracts.

At September 30, 2007, the Company had futures contracts covering 2.8 Bcf (net long position) at a weighted average contract price of $9.11 per Mcf.

The Company may be exposed to credit risk on some of the derivatives disclosed above. 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 an ongoing basis, monitors counterparty credit exposure. Management has obtained guarantees from many of the parent companies of the respective counterparties to its derivatives. At September 30, 2008, the Company had eleven counterparties for its over the counter derivative financial instruments and no individual counterparty represented greater than 42% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company s total over the counter volumes hedged). The Company recorded a $0.6 million reduction to the fair market value of its derivative assets based on its assessment of counterparty credit risk. This credit reserve was determined by applying default probabilities to the anticipated cash flows that the Company is expecting from its counterparties.

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### 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. The interest rates for the variable rate debt are based on those in effect at September 30, 2008:

| | Principal Amounts by Expected Maturity Dates | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2009 | 2010 | 2011 | 2012 | 2013 | Thereafter | Total |
| | (Dollars in millions) | | | | | | |
| Long-Term Fixed Rate Debt | $ 100.0(1) | $ | $ 200.0 | $ 150.0 | $ 250.0 | $ 399.0 | $ 1,099.0 |
| Weighted Average Interest Rate Paid | 6.0% | | 7.5% | 6.7% | 5.3% | 6.7% | 6.5% |
| Fair Value of Long-Term Fixed Rate Debt = $1,027.1 | | | | | | | |

(1) These notes have been classified as Current Portion of Long-Term Debt on the Company s Consolidated Balance Sheet.

## RATE AND REGULATORY MATTERS

### Utility Operation

Base rate adjustments in both the New York and Pennsylvania jurisdictions do not reflect the recovery of purchased gas costs. Such costs are recovered through operation of the purchased gas adjustment clauses of the appropriate regulatory authorities.

### New York Jurisdiction

On January 29, 2007, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by $52.0 million. Following standard procedure, the NYPSC suspended the proposed tariff amendments to enable its staff and intervenors to conduct a routine investigation and hold hearings. Distribution Corporation explained in the filing that its request for rate relief was necessitated by decreased revenues resulting from customer conservation efforts and increased customer uncollectibles, among other things. The rate filing also included a proposal for an efficiency and conservation initiative with a revenue decoupling mechanism designed to render the Company indifferent to throughput reductions resulting from conservation. On September 20, 2007, the NYPSC issued an order approving, with modifications, Distribution Corporation s conservation program for implementation on an accelerated basis. Associated ratemaking issues, however, were reserved for consideration in the rate.

On December 21, 2007, the NYPSC issued a rate order providing for an annual rate increase of $1.8 million, together with a monthly bill surcharge that would collect up to $10.8 million to recover expenses for implementation of the conservation program. The rate increase and bill surcharge became effective December 28, 2007. The rate order further provided for a return on equity of 9.1%. The rate order also adopted Distribution Corporation s proposed revenue decoupling mechanism. The revenue decoupling mechanism, like others, 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 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 contends that portions of the rate order should be invalidated because they fail to meet the applicable legal standard for agency decisions. Among the issues challenged by the Company are the reasonableness of the NYPSC s disallowance of expense items, including health care costs, and the methodology used for calculating rate of return, which the appeal contends understated the Company s cost of equity. The Company cannot predict the outcome of the appeal at this time.

**Pennsylvania Jurisdiction**

On June 1, 2006, Distribution Corporation filed proposed tariff amendments with PaPUC to increase annual revenues by $25.9 million to cover increases in the cost of service to be effective July 30, 2006. The rate request was filed to address increased costs associated with Distribution Corporation s ongoing construction program as well as increases in operating costs, particularly uncollectible accounts. Following standard regulatory procedure, the PaPUC issued an order on July 20, 2006 instituting a rate proceeding and suspending the proposed tariff amendments until March 2, 2007. On October 2, 2006, the parties, including Distribution Corporation, Staff of the PaPUC and intervenors, executed an agreement (Settlement) proposing to settle all issues in the rate proceeding. The Settlement included an increase in annual revenues of $14.3 million to non-gas revenues, an agreement not to file a rate case until January 28, 2008 at the earliest and an early implementation date. The Settlement was approved by the PaPUC at its meeting on November 30, 2006, and the new rates 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 currently does not have a rate case on file with the NYPSC. Among the issues resolved in connection with Empire s FERC application to build the Empire Connector are the rates and terms of service that will become applicable to all of Empire s business, effective upon Empire constructing and placing its new facilities into service (currently expected for December 2008). At that time, Empire will become an interstate pipeline subject to FERC regulation. The order described in the following paragraph requires Empire to make a filing at the FERC, within three years after the in-service date, justifying Empire s existing recourse rates or proposing alternative rates.

On December 21, 2006, the FERC issued an order granting a Certificate of Public Convenience and Necessity authorizing the construction and operation of the Empire Connector and various other related pipeline projects by other unaffiliated companies. The Empire Certificate contains various environmental and other conditions. Empire accepted that Certificate and received additional environmental permits from the U.S. Army Corps of Engineers and state environmental agencies. Empire also received, from all six upstate New York counties in which it will build the Empire Connector project, final approval of sales tax exemptions and temporary partial property tax abatements. In June 2007, Empire signed a firm transportation service agreement with KeySpan Gas East Corporation, under which Empire is obligated to provide transportation service that required construction of this project. Construction began in September 2007 and is anticipated to be ready to commence service in December 2008, on or before the in-service date of the Millennium Pipeline to which it will connect.

**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, 2008, 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 $19.4 million to $23.6 million. The minimum estimated liability of $19.4 million has been recorded on the Consolidated Balance Sheet at September 30, 2008. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet. Other than discussed in Note H (referred to below), the Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations or other factors could adversely impact the Company.

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

**NEW ACCOUNTING PRONOUNCEMENTS**

In September 2006, the FASB issued SFAS 157. SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement 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. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. In accordance with FASB Staff Position FAS No. 157-2, SFAS 157 is effective for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis as of the Company s first quarter of fiscal 2009. The same FASB Staff Position delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value on a recurring basis, until the Company s first quarter of fiscal 2010. The Company does not expect that SFAS 157 will have a significant impact on its consolidated financial statements.

In September 2006, the FASB also issued SFAS 158, an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R. SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan s assets and obligations that determine its funded status be measured as of the end of the Company s fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date. At September 30, 2007, in order to recognize the funded status of its pension and post-retirement benefit plans in accordance with SFAS 158, the Company recorded additional liabilities or reduced assets by a cumulative amount of $78.7 million ($71.1 million net of deferred tax benefits recognized for the portion recorded as an increase to Accumulated Other Comprehensive Loss). Of the $71.1 million recognized, $61.9 million was recorded as an increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments, $12.5 million (net of deferred tax benefits of $7.6 million) was recorded as an increase to Accumulated Other Comprehensive Loss, and $3.3 million was recorded as an increase to Other Regulatory Liabilities in the Company s Utility segment. The Company has recorded amounts to Other Regulatory Assets or Other Regulatory Liabilities in the Utility and Pipeline and Storage segments in accordance with the provisions of SFAS 71. The Company, in those segments, has certain regulatory commission authorizations, which allow the Company to defer as a regulatory asset or liability the difference between pension and post-retirement benefit costs as calculated in accordance with SFAS 87 and SFAS 106 and what is collected in rates. Refer to Item 8 at Note G Retirement Plan and Other Post-Retirement Benefits for further disclosures regarding the impact of SFAS 158 on the Company s consolidated financial statements.

In February 2007, the FASB issued SFAS 159. SFAS 159 permits entities to choose to measure many financial instruments at fair value that are not otherwise required to be measured at fair value under GAAP. A company that elects the fair value option for an eligible item will be required to recognize in current earnings any changes in that item s fair value in reporting periods subsequent to the date of adoption. SFAS 159 is effective as of the Company s first quarter of fiscal 2009. The Company does not plan to elect the fair value measurement option for any of its financial instruments other than those that are already being measured at fair value.

In December 2007, the FASB issued SFAS 141R. SFAS 141R will significantly change the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under SFAS 141R, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. SFAS 141R is effective as of the Company s first quarter of fiscal 2010.

In December 2007, the FASB issued SFAS 160. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. SFAS 160 is effective as of the Company s first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued SFAS 161. SFAS 161 requires entities to provide enhanced disclosures related to an entity s derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity s financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective as of the Company s second quarter of fiscal 2009. The Company is currently evaluating the impact that the adoption of SFAS 161 will have on its disclosures in the notes to the 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 their effect on the Company s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments;
2. Occurrences affecting the Company s ability to obtain financing under credit lines or other credit facilities or through the issuance of commercial paper, other short-term notes or debt or equity securities, including any downgrades in the Company s credit ratings and changes in interest rates and other capital market conditions;
3. 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;
4. The creditworthiness or performance of the Company s key suppliers, customers and counterparties;
5. 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;
6. 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;
7. Changes in demographic patterns and weather conditions;
8. 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 or the valuation of the Company s natural gas and oil reserves;
9. Impairments under the SEC s full cost ceiling test for natural gas and oil reserves;
10. Uncertainty of oil and gas reserve estimates;
11. Ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including shortages, delays or unavailability of equipment and services required in drilling operations;
12. Significant changes from expectations in the Company s actual production levels for natural gas or oil;
13. Changes in the availability and/or price of derivative financial instruments;
14. Changes in the price differentials between various types of oil;
15. Inability to obtain new customers or retain existing ones;
16. Significant changes in competitive factors affecting the Company;
17. Changes in laws and regulations to which the Company is subject, including tax, environmental, safety and employment laws and regulations;
18. Governmental/regulatory actions, initiatives and proceedings, including those involving 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. Significant changes from expectations in actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs or plans;

21. The nature and projected profitability of pending and potential projects and other investments, and the ability to obtain necessary governmental approvals and permits;

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

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23. Changes in the market price of timber and the impact such changes might have on the types and quantity of timber harvested by the Company;

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

25. 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;

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

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

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

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

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

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

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

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

***Index to Financial Statements***



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

***Supplementary Data***

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

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2008 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, 2008, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management s Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

Buffalo, New York
November 26, 2008

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**NATIONAL FUEL GAS COMPANY**

**CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS**

| | Year Ended September 30 | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| | (Thousands of dollars, except per common share amounts) | | |
| **INCOME** | | | |
| **Operating Revenues** | $ 2,400,361 | $ 2,039,566 | $ 2,239,675 |
| **Operating Expenses** | | | |
| Purchased Gas | 1,235,157 | 1,018,081 | 1,267,562 |
| Operation and Maintenance | 432,871 | 396,408 | 395,289 |
| Property, Franchise and Other Taxes | 75,585 | 70,660 | 69,202 |
| Depreciation, Depletion and Amortization | 170,623 | 157,919 | 151,999 |
| | 1,914,236 | 1,643,068 | 1,884,052 |
| **Operating Income** | 486,125 | 396,498 | 355,623 |
| **Other Income (Expense):** | | | |
| Income from Unconsolidated Subsidiaries | 6,303 | 4,979 | 3,583 |
| Other Income | 7,376 | 4,936 | 2,825 |
| Interest Income | 10,815 | 1,550 | 9,409 |
| Interest Expense on Long-Term Debt | (70,099) | (68,446) | (72,629) |
| Other Interest Expense | (3,870) | (6,029) | (5,952) |
| **Income from Continuing Operations Before Income Taxes** | 436,650 | 333,488 | 292,859 |
| Income Tax Expense | 167,922 | 131,813 | 108,245 |
| **Income from Continuing Operations** | 268,728 | 201,675 | 184,614 |
| **Discontinued Operations:** | | | |
| Income (Loss) from Operations, Net of Tax | | 15,479 | (46,523) |
| Gain on Disposal, Net of Tax | | 120,301 | |
| **Income (Loss) from Discontinued Operations, Net of Tax** | | 135,780 | (46,523) |
| **Net Income Available for Common Stock** | 268,728 | 337,455 | 138,091 |
| **EARNINGS REINVESTED IN THE BUSINESS** | | | |
| Balance at Beginning of Year | 983,776 | 786,013 | 813,020 |
| | 1,252,504 | 1,123,468 | 951,111 |
| Share Repurchases | (194,776) | (38,196) | (66,269) |
| Cumulative Effect of Adoption of FIN 48 | (406) | | |
| Dividends on Common Stock | (103,523) | (101,496) | (98,829) |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Balance at End of Year** | $ | 953,799 | $ | 983,776 | $ | 786,013 |
| **Earnings Per Common Share:** | | | | | | |
| Basic: | | | | | | |
| Income from Continuing Operations | $ | 3.27 | $ | 2.43 | $ | 2.20 |
| Income (Loss) from Discontinued Operations | | | | 1.63 | | (0.56) |
| **Net Income Available for Common Stock** | $ | 3.27 | $ | 4.06 | $ | 1.64 |
| Diluted: | | | | | | |
| Income from Continuing Operations | $ | 3.18 | $ | 2.37 | $ | 2.15 |
| Income (Loss) from Discontinued Operations | | | | 1.59 | | (0.54) |
| **Net Income Available for Common Stock** | $ | 3.18 | $ | 3.96 | $ | 1.61 |
| **Weighted Average Common Shares Outstanding:** | | | | | | |
| Used in Basic Calculation | | 82,304,335 | | 83,141,640 | | 84,030,118 |
| Used in Diluted Calculation | | 84,474,839 | | 85,301,361 | | 86,028,466 |

See Notes to Consolidated Financial Statements

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**NATIONAL FUEL GAS COMPANY**

**CONSOLIDATED BALANCE SHEETS**

| | At September 30 | |
|---|---|---|
| | **2008** | **2007** |
| | **(Thousands of dollars)** | |
| **ASSETS** | | |
| **Property, Plant and Equipment** | $ 4,873,969 | $ 4,461,586 |
| Less Accumulated Depreciation, Depletion and Amortization | 1,719,869 | 1,583,181 |
| | 3,154,100 | 2,878,405 |
| **Current Assets** | | |
| Cash and Temporary Cash Investments | 68,239 | 124,806 |
| Cash Held in Escrow | | 61,964 |
| Hedging Collateral Deposits | 1 | 4,066 |
| Receivables Net of Allowance for Uncollectible Accounts of $33,117 and $28,654, Respectively | 185,397 | 172,380 |
| Unbilled Utility Revenue | 24,364 | 20,682 |
| Gas Stored Underground | 87,294 | 66,195 |
| Materials and Supplies at average cost | 31,317 | 35,669 |
| Unrecovered Purchased Gas Costs | 37,708 | 14,769 |
| Other Current Assets | 65,158 | 45,057 |
| Deferred Income Taxes | | 8,550 |
| | 499,478 | 554,138 |
| **Other Assets** | | |
| Recoverable Future Taxes | 82,506 | 83,954 |
| Unamortized Debt Expense | 13,978 | 12,070 |
| Other Regulatory Assets | 189,587 | 137,577 |
| Deferred Charges | 4,417 | 5,545 |
| Other Investments | 80,640 | 85,902 |
| Investments in Unconsolidated Subsidiaries | 16,279 | 18,256 |
| Goodwill | 5,476 | 5,476 |
| Intangible Assets | 26,174 | 28,836 |
| Prepaid Pension and Other Post-Retirement Benefit Costs | 21,034 | 61,006 |
| Fair Value of Derivative Financial Instruments | 28,786 | 9,188 |
| Other | 7,732 | 8,059 |
| | 476,609 | 455,869 |
| **Total Assets** | $ 4,130,187 | $ 3,888,412 |

**CAPITALIZATION AND LIABILITIES**

| | | |
|---|---|---|
| **Capitalization:** | | |
| **Comprehensive Shareholders Equity** | | |
| Common Stock, $1 Par Value | | |
| Authorized 200,000,000 Shares; Issued and Outstanding 79,120,544 Shares and 83,461,308 Shares, Respectively | $ 79,121 | $ 83,461 |
| Paid In Capital | 567,716 | 569,085 |
| Earnings Reinvested in the Business | 953,799 | 983,776 |
| Total Common Shareholders Equity Before Items Of Other Comprehensive Income (Loss) | 1,600,636 | 1,636,322 |
| Accumulated Other Comprehensive Income (Loss) | 2,963 | (6,203) |
| **Total Comprehensive Shareholders Equity** | 1,603,599 | 1,630,119 |
| **Long-Term Debt, Net of Current Portion** | 999,000 | 799,000 |
| **Total Capitalization** | 2,602,599 | 2,429,119 |
| **Current and Accrued Liabilities** | | |
| Notes Payable to Banks and Commercial Paper | | |
| Current Portion of Long-Term Debt | 100,000 | 200,024 |
| Accounts Payable | 142,520 | 109,757 |
| Amounts Payable to Customers | 2,753 | 10,409 |
| Dividends Payable | 25,714 | 25,873 |
| Interest Payable on Long-Term Debt | 22,114 | 18,158 |
| Customer Advances | 33,017 | 22,863 |
| Other Accruals and Current Liabilities | 45,220 | 36,062 |
| Deferred Income Taxes | 1,871 | |
| Fair Value of Derivative Financial Instruments | 1,362 | 16,200 |
| | 374,571 | 439,346 |
| **Deferred Credits** | | |
| Deferred Income Taxes | 634,372 | 575,356 |
| Taxes Refundable to Customers | 18,449 | 14,026 |
| Unamortized Investment Tax Credit | 4,691 | 5,392 |
| Cost of Removal Regulatory Liability | 103,100 | 91,226 |
| Other Regulatory Liabilities | 91,933 | 76,659 |
| Pension and Other Post-Retirement Liabilities | 78,909 | 70,555 |
| Asset Retirement Obligations | 93,247 | 75,939 |
| Other Deferred Credits | 128,316 | 110,794 |
| | 1,153,017 | 1,019,947 |
| **Commitments and Contingencies** | | |
| **Total Capitalization and Liabilities** | $ 4,130,187 | $ 3,888,412 |

See Notes to Consolidated Financial Statements

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**NATIONAL FUEL GAS COMPANY**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | Year Ended September 30 | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| | (Thousands of dollars) | | |
| **Operating Activities** | | | |
| Net Income Available for Common Stock | $ 268,728 | $ 337,455 | $ 138,091 |
| Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities: | | | |
| Gain on Sale of Discontinued Operations | | (159,873) | |
| Impairment of Oil and Gas Producing Properties | | | 104,739 |
| Depreciation, Depletion and Amortization | 170,623 | 170,803 | 179,615 |
| Deferred Income Taxes | 72,496 | 52,847 | (5,230) |
| Income from Unconsolidated Subsidiaries, Net of Cash Distributions | 1,977 | (3,366) | 1,067 |
| Excess Tax Benefits Associated with Stock-Based Compensation Awards | (16,275) | (13,689) | (6,515) |
| Other | 4,858 | 16,399 | 4,829 |
| Change in: | | | |
| Hedging Collateral Deposits | 4,065 | 15,610 | 58,108 |
| Receivables and Unbilled Utility Revenue | (16,815) | 5,669 | (12,343) |
| Gas Stored Underground and Materials and Supplies | (22,116) | (5,714) | 1,679 |
| Unrecovered Purchased Gas Costs | (22,939) | (1,799) | 1,847 |
| Prepayments and Other Current Assets | (36,376) | 18,800 | (39,572) |
| Accounts Payable | 32,763 | (26,002) | (23,144) |
| Amounts Payable to Customers | (7,656) | (13,526) | 22,777 |
| Customer Advances | 10,154 | (6,554) | 4,946 |
| Other Accruals and Current Liabilities | (3,641) | 8,950 | (17,754) |
| Other Assets | (11,887) | 4,109 | (22,700) |
| Other Liabilities | 54,817 | (5,922) | 80,960 |
| **Net Cash Provided by Operating Activities** | 482,776 | 394,197 | 471,400 |
| **Investing Activities** | | | |
| Capital Expenditures | (397,734) | (276,728) | (294,159) |
| Investment in Partnership | | (3,300) | |
| Net Proceeds from Sale of Foreign Subsidiaries | | 232,092 | |
| Cash Held in Escrow | 58,397 | (58,248) | |
| Net Proceeds from Sale of Oil and Gas Producing Properties | 5,969 | 5,137 | 13 |
| Other | 4,376 | (725) | (3,230) |
| **Net Cash Used in Investing Activities** | (328,992) | (101,772) | (297,376) |
| **Financing Activities** | | | |
| Excess Tax Benefits Associated with Stock-Based Compensation Awards | 16,275 | 13,689 | 6,515 |

| | | | |
|---|---|---|---|
| Shares Repurchased under Repurchase Plan | (237,006) | (48,070) | (85,168) |
| Net Proceeds from Issuance of Long-Term Debt | 296,655 | | |
| Reduction of Long-Term Debt | (200,024) | (119,576) | (9,805) |
| Net Proceeds from Issuance of Common Stock | 17,432 | 17,498 | 23,339 |
| Dividends Paid on Common Stock | (103,683) | (100,632) | (98,266) |
| **Net Cash Used in Financing Activities** | (210,351) | (237,091) | (163,385) |
| **Effect of Exchange Rates on Cash** | | (139) | 1,365 |
| **Net Increase (Decrease) in Cash and Temporary Cash Investments** | (56,567) | 55,195 | 12,004 |
| **Cash and Temporary Cash Investments At Beginning of Year** | 124,806 | 69,611 | 57,607 |
| **Cash and Temporary Cash Investments At End of Year** | $ 68,239 | $ 124,806 | $ 69,611 |
| **Supplemental Disclosure of Cash Flow Information** | | | |
| **Cash Paid For:** | | | |
| Interest | $ 69,841 | $ 75,987 | $ 78,003 |
| Income Taxes | $ 103,154 | $ 97,961 | $ 54,359 |

See Notes to Consolidated Financial Statements

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## NATIONAL FUEL GAS COMPANY

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | (Thousands of dollars) | | |
| Net Income Available for Common Stock | $ 268,728 | $ 337,455 | $ 138,091 |
| Other Comprehensive Income (Loss), Before Tax: | | | |
| Minimum Pension Liability Adjustment | | | 165,914 |
| Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans | (13,584) | | |
| Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans | 1,924 | | |
| Foreign Currency Translation Adjustment | 12 | 7,874 | 7,408 |
| Reclassification Adjustment for Realized Foreign Currency Translation Gain in Net Income | | (42,658) | (716) |
| Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period | (4,856) | 4,747 | 2,573 |
| Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period | (31,490) | 8,495 | 90,196 |
| Reclassification Adjustment for Realized Losses on Derivative Financial Instruments in Net Income | 64,645 | 5,106 | 91,743 |
| Other Comprehensive Income (Loss), Before Tax | 16,651 | (16,436) | 357,118 |
| Income Tax Expense Related to Minimum Pension Liability Adjustment | | | 58,070 |
| Income Tax Benefit Related to the Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans | (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 | 726 | | |
| Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period | (1,434) | 1,724 | 894 |
| Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period | (13,228) | 3,153 | 34,772 |
| Reclassification Adjustment for Income Tax Benefit on Realized Losses on Derivative Financial Instruments In Net Income | 26,548 | 2,824 | 35,338 |
| Income Taxes Net | 7,485 | 7,701 | 129,074 |
| Other Comprehensive Income (Loss) | 9,166 | (24,137) | 228,044 |
| Comprehensive Income | $ 277,894 | $ 313,318 | $ 366,135 |

See Notes to Consolidated Financial Statements

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## 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.

***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 calendar month 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 Timber segment records revenue on lumber and log sales as products are shipped, which is the point at which ownership and risk of loss transfers to the buyer of lumber products or logs.

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.

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 in fixed monthly reservation charges. The allowed rates that Empire bills its customers are based on a modified fixed-variable rate design, which allows recovery of most fixed costs in fixed monthly reservation charges. To distinguish between the two rate designs, the modified fixed-variable rate design recovers return on equity and income taxes through variable charges whereas straight fixed-variable recovers all fixed costs, including return on equity and income taxes, through its monthly reservation charge. Because of the difference in rate design, changes in throughput due to weather variations do not have a significant impact on Supply Corporation s revenues but may have a significant impact on Empire s revenues.

***Property, Plant and Equipment***

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

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

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

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

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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 current market 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. 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, 2008, 2007, and 2006, estimated future net cash flows were increased by $34.5 million, $2.2 million and $4.7 million, respectively. The Company s capitalized costs exceeded the full cost ceiling for the Company s Canadian properties at June 30, 2006 and September 30, 2006. As such, the Company recognized pre-tax impairments of $62.4 million at June 30, 2006 and $42.3 million at September 30, 2006. These impairment charges are included in loss from discontinued operations for 2006 due to the sale of SECI during 2007.

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

***Depreciation, Depletion and Amortization***

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

| | As of September 30 | |
|---|---|---|
| | 2008 | 2007 |
| | (Thousands) | |
| Utility | $ 1,580,366 | $ 1,539,808 |
| Pipeline and Storage | 996,743 | 976,316 |
| Exploration and Production | 1,800,422 | 1,577,745 |
| Energy Marketing | 1,232 | 1,199 |
| Timber | 120,021 | 119,237 |
| All Other and Corporate | 25,984 | 32,806 |
| | $ 4,524,768 | $ 4,247,111 |

Average depreciation, depletion and amortization rates are as follows:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| Utility | 2.6% | 2.8% | 2.8% |
| Pipeline and Storage | 3.2% | 3.5% | 4.0% |
| Exploration and Production, per Mcfe(1) | $ 2.26 | $ 1.94 | $ 2.00 |
| Energy Marketing | 3.5% | 2.8% | 4.8% |
| Timber | 4.1% | 4.0% | 5.6% |
| All Other and Corporate | 5.0% | 4.6% | 4.1% |

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note O Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $2.23, $1.92 and $1.98 per Mcfe of production in 2008, 2007 and 2006, respectively. Depletion of oil and gas producing properties in the United States amounted to $2.23, $1.97 and $1.74 per Mcfe of production in 2008, 2007 and 2006, respectively. Depletion of oil and gas producing properties in Canada amounted $1.67 and $2.95 per Mcfe of production in 2007 and 2006, respectively.

***Goodwill***

The Company has recognized goodwill of $5.5 million as of September 30, 2008 and 2007 on its consolidated balance sheet related to the Company s acquisition of Empire in 2003. The Company accounts for goodwill in accordance with SFAS 142, which requires the Company to test goodwill for impairment annually. At September 30, 2008 and 2007, the fair value of Empire was greater than its book value. As such, the goodwill was considered not impaired.

***Financial Instruments***

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

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments include price swap agreements and futures contracts. The Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled fair value of derivative financial instruments. Fair value represents the amount the Company would receive or pay to terminate these instruments.

For effective cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues, purchased gas expense or interest expense on the Consolidated Statements of Income. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statements of Income. In December 2006, the Company repaid $22.8 million of Empire s secured debt. The interest costs of this secured debt were hedged by an interest rate collar. Since the hedged transaction was settled and there will be no future cash flows associated with the secured debt, hedge accounting for the interest rate collar was discontinued and the unrealized gain of $1.9 million in accumulated other comprehensive income associated with the interest rate collar was reclassified to the Consolidated Statement of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2008 or 2006.

For fair value hedges, the offset to the asset or liability that is recorded is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheets representing the change in fair value of the asset or firm commitment that is being hedged (see Other Current Assets section in this footnote). The offset to this asset or liability is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income as well. If the fair value hedge is effective, the gain or loss from the derivative financial instrument is offset by the gain or loss that arises from the change in fair value of the asset or firm commitment that is being hedged. The Company did not experience any material ineffectiveness with regard to its fair value hedges during 2008, 2007 or 2006.

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

***Accumulated Other Comprehensive Income (Loss)***

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

| | Year Ended September 30 2008 | Year Ended September 30 2007 |
|---|---|---|
| | (Thousands) | |
| Funded Status of the Pension and Other Post-Retirement Benefit Plans | $ (19,741) | $ (12,482)(1) |
| Cumulative Foreign Currency Translation Adjustment | (71) | (83) |
| Net Unrealized Gain (Loss) on Derivative Financial Instruments | 15,949 | (3,886) |
| Net Unrealized Gain on Securities Available for Sale | 6,826 | 10,248 |
| Accumulated Other Comprehensive Income (Loss) | $ 2,963 | $ (6,203) |

(1) In accordance with the transition recognition implementation provisions of SFAS 158, the adjustment to recognize the funded status of the pension and other post-retirement benefit plans are shown as an adjustment to the ending balance of accumulated other comprehensive income (loss). The adjustment is not shown as other comprehensive income (loss) in the Consolidated Statements of Comprehensive Income.

At September 30, 2008, it is estimated that of the $15.9 million net unrealized gain on derivative financial instruments shown in the table above, $13.1 million will be reclassified into the Consolidated Statement of Income during 2009. The remaining unrealized gain on derivative financial instruments of $2.8 million will be reclassified into the Consolidated Statement of Income in subsequent years. As disclosed in Note F Financial Instruments, the Company s derivative financial instruments extend out to 2012.

The amounts included in accumulated other comprehensive income (loss) related to the funded status of the Company s pension and other post-retirement benefit plans consist of an unrecognized transition obligation, prior service costs and accumulated losses. The total unrecognized transition obligation was $0.1 million at September 30, 2007 (nothing at September 30, 2008). The total amount for prior service costs was $0.4 million and $1.0 million at September 30, 2008 and September 30, 2007, respectively. The total amount for accumulated losses was $19.3 million and $11.4 million at September 30, 2008 and September 30, 2007, respectively.

***Gas Stored Underground Current***

In the Utility segment, gas stored underground current in the amount of $34.1 million is carried at lower of cost or market, on a LIFO method. Based upon the average price of spot market gas purchased in September 2008, including transportation costs, the current cost of replacing this inventory of gas stored underground current exceeded the amount stated on a LIFO basis by approximately $195.4 million at September 30, 2008. All other gas stored underground current, which is in the Energy Marketing segment, is carried at lower of cost or market on an average cost method.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***Purchased Timber Rights***

In the Timber segment, the Company purchases the right to harvest timber from land owned by other parties. These rights, which extend from several months to several years, are purchased to ensure an adequate supply of timber for the Company s sawmill and kiln operations. The historical value of timber rights expected to be harvested during the following year are included in Materials and Supplies on the Consolidated Balance Sheets while the historical value of timber rights expected to be harvested beyond one year are included in Other Assets on the Consolidated Balance Sheets. The components of the Company s purchased timber rights are as follows:

| | Year Ended September 30 2008 | Year Ended September 30 2007 |
|---|---|---|
| | (Thousands) | |
| Materials and Supplies | $ 9,911 | $ 8,925 |
| Other Assets | 7,383 | 5,641 |
| | $ 17,294 | $ 14,566 |

***Unamortized Debt Expense***

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

***Foreign Currency Translation***

The functional currency for the Company s foreign operations is the local currency of the country where the operations are located. Asset and liability accounts are translated at the rate of exchange on the balance sheet date. Revenues and expenses are translated at the average exchange rate during the period. Foreign currency translation adjustments are recorded as a component of accumulated other comprehensive income (loss). With the sale of SECI on August 31, 2007, the Company eliminated its major foreign operation. While the Company is in the process of winding up or selling certain power development projects in Europe, the investment in such projects is not significant and the Company does not expect to have any significant foreign currency translation adjustments in the future.

***Income Taxes***

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

***Consolidated Statements of Cash Flows***

For purposes of the Consolidated Statements of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. At September 30, 2008, the Company accrued $16.8 million of capital expenditures related to the construction of the Empire Connector project. This amount has been excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represents a non-cash investing activity at that date.

***Hedging Collateral Account***

Cash held in margin accounts serves as collateral for open positions on exchange-traded futures contracts, exchange-traded options and over-the-counter swaps and collars.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***Cash Held in Escrow***

On August 31, 2007, the Company received approximately $232.1 million of proceeds from the sale of SECI, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. The escrow account was a Canadian dollar denominated account. On a U.S. dollar basis, the value of this account was $62.0 million at September 30, 2007. In December 2007, the Canadian government issued the tax clearance certificate, thereby releasing the proceeds from restriction as of December 31, 2007. To hedge against foreign currency exchange risk related to the cash being held in escrow, the Company held a forward contract to sell Canadian dollars. For presentation purposes on the Consolidated Statement of Cash Flows, for the year ended September 30, 2008, the Cash Held in Escrow line item within Investing Activities reflects the net proceeds to the Company (received on January 8, 2008) after adjusting for the impact of the foreign currency hedge.

***Other Current Assets***

Other Current Assets consist of prepayments in the amounts of $10.6 million and $14.1 million at September 30, 2008 and 2007, respectively, prepaid property and other taxes of $11.2 million and $14.1 million at September 30, 2008 and 2007, respectively, federal income taxes receivable in the amounts of $27.5 million and $8.7 million at September 30, 2008 and 2007, respectively, state income taxes receivable in the amounts of $5.0 million and zero at September 30, 2008 and 2007, respectively, and fair values of firm commitments in the amounts of $10.9 million and $8.2 million at September 30, 2008 and 2007, respectively.

***Earnings Per Common Share***

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options and stock-settled SARs. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these stock options and stock-settled SARs as determined using the Treasury Stock Method. Stock options and stock-settled SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2008, there were 7,344 stock-settled SARs excluded as being antidilutive, and there were no stock options excluded as being antidilutive. For 2007, no stock options or stock-settled SARs were excluded as being antidilutive. For 2006, 119,241 stock options were excluded as being antidilutive. There were no stock-settled SARs excluded as being antidilutive for 2006.

***Share Repurchases***

The Company considers all shares repurchased as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. The repurchases are accounted for on the date the share repurchase is settled as an adjustment to common stock (at par value) with the excess repurchase price allocated between paid in capital and retained earnings. Refer to Note E Capitalization and Short-Term Borrowings for further discussion of the share repurchase program.

***Stock-Based Compensation***

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, stock-settled SARs, restricted stock, performance units or performance shares. Stock options and stock-settled SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no stock option or stock-settled SAR is exercisable less than one year or more than ten years

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

after the date of each grant. Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. Certificates for shares of restricted stock awarded under the Company s stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant.

Prior to October 1, 2005, the Company accounted for its stock-based compensation under the recognition and measurement principles of APB 25 and related interpretations. Under that method, no compensation expense was recognized for options granted under the Company s stock option and stock award plans. The Company did record, in accordance with APB 25, compensation expense for the market value of restricted stock on the date of the award over the periods during which the vesting restrictions existed.

Effective October 1, 2005, the Company adopted SFAS 123R, which requires the measurement and recognition of compensation cost at fair value for all share-based payments, including stock options and stock-settled SARs. The Company has chosen to use the modified version of prospective application, as allowed by SFAS 123R. Using the modified prospective application, the Company recorded compensation cost for the portion of awards granted prior to October 1, 2005 for which the requisite service had not been rendered and recognized such compensation cost as the requisite service was rendered on or after October 1, 2005. Such compensation expense is based on the grant-date fair value of the awards as calculated for the Company s disclosure using a Binomial option-pricing model under SFAS 123. Any new awards, modifications to awards, repurchases of awards, or cancellations of awards subsequent to September 30, 2005 will follow the provisions of SFAS 123R, with compensation expense being calculated using the Black-Scholes-Merton closed form model. The Company has chosen the Black-Scholes-Merton closed form model since it is easier to administer than the Binomial option-pricing model. Furthermore, since the Company does not have complex stock-based compensation awards, it does not believe that compensation expense would be materially different under either model. There were no stock options granted during the year ended September 30, 2008. There were 448,000 and 317,000 stock options granted during the years ended September 30, 2007 and 2006, respectively. The Company granted 321,000 performance based stock-settled SARs during the year ended September 30, 2008. There were no performance based stock-settled SARs granted during the year ended September 30, 2007. The Company granted 50,000 non-performance based stock-settled SARs during the year ended September 30, 2007. There were no non-performance based stock-settled SARs granted during the year ended September 30, 2008. There were no performance based or non-performance based stock-settled SARs granted during the year ended September 30, 2006. The accounting treatment for such performance based and non-performance based stock-settled SARs is the same under SFAS 123R as the accounting for stock options under SFAS 123R. The performance based stock-settled SARs granted for the year ended September 30, 2008 vest and become exercisable annually, in one-third increments, provided that a performance condition for diluted earnings per share is met for the prior fiscal year. The weighted average grant date fair value of the performance based stock-settled SARs granted during 2008 was estimated on the date of grant using the same accounting treatment that is applied for stock options under SFAS 123R, and assumes that the performance conditions specified will be achieved. If such conditions are not met, no compensation expense is recognized and any recognized compensation expense is reversed. The Company also granted 25,000, 25,000 and 16,000 restricted share awards (non-vested stock as defined by SFAS 123R) during the years ended September 30, 2008, 2007 and 2006, respectively. Stock-based compensation expense for the years ended September 30, 2008, 2007 and 2006 was approximately $2,332,000, $3,727,000, and $1,705,000, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statement of Income. The total income tax benefit related to stock-based compensation expense during the years ended

September 30, 2008, 2007 and 2006 was approximately $945,000, $1,488,000 and $653,000, respectively. There were no capitalized stock-based compensation costs during the years ended September 30, 2008 and 2007.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***Stock Options***

The total intrinsic value of stock options exercised during the years ended September 30, 2008, 2007 and 2006 totaled approximately $24.6 million, $38.7 million, and $30.9 million, respectively. For 2008, 2007 and 2006, the amount of cash received by the Company from the exercise of such stock options was approximately $18.5 million, $26.0 million, and $30.1 million, respectively.

The Company realizes tax benefits related to the exercise of stock options on a calendar year basis as opposed to a fiscal year basis. As such, for stock options exercised during the quarters ended December 31, 2007, 2006, and 2005, the Company realized a tax benefit of $4.4 million, $3.2 million, and $0.9 million, respectively. For stock options exercised during the period of January 1, 2008 through September 30, 2008, the Company will realize a tax benefit of approximately $4.3 million in the quarter ended December 31, 2008. For stock options exercised during the period of January 1, 2007 through September 30, 2007, the Company realized a tax benefit of approximately $12.0 million in the quarter ended December 31, 2007. For stock options exercised during the period of January 1, 2006 through September 30, 2006, the Company realized a tax benefit of approximately $11.4 million in the quarter ended December 31, 2006. The weighted average grant date fair value of options granted in 2007 and 2006 is $7.27 per share and $6.68 per share, respectively. For the years ended September 30, 2008, 2007 and 2006, 358,000, 327,501 and 89,665 stock options became fully vested, respectively. The total fair value of these stock options was approximately $2.6 million, $2.1 million and $0.4 million, respectively, for the years ended September 30, 2008, 2007 and 2006. As of September 30, 2008, unrecognized compensation expense related to stock options totaled approximately $0.3 million, which will be recognized over a weighted average period of 8.6 months. For a summary of transactions during 2008 involving option shares for all plans, refer to Note E Capitalization and Short-Term Borrowings.

The fair value of options at the date of grant was estimated using a Binomial option-pricing model for options granted prior to October 1, 2005 and the Black-Scholes-Merton closed form model for options granted after September 30, 2005. The following weighted average assumptions were used in estimating the fair value of options at the date of grant:

| | **Year Ended September 30** | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| Risk Free Interest Rate | N/A | 4.46% | 5.08% |
| Expected Life (Years) | N/A | 7.0 | 7.0 |
| Expected Volatility | N/A | 17.73% | 17.71% |
| Expected Dividend Yield (Quarterly) | N/A | 0.76% | 0.83% |

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

For grants during the years ended September 30, 2007 and 2006, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

***Non-Performance Based Stock-settled SARs***

There were no non-performance based stock-settled SARs exercised during the years ended September 30, 2008, 2007 and 2006 as none of the non-performance based stock-settled SARs granted have vested. There were 50,000 non-performance based stock-settled SARs granted during 2007. The weighted average grant date fair value of non-performance based stock-settled SARs granted in 2007 is $7.81 per share. There were no non-performance based stock-settled SARs granted during 2008 or 2006. As of September 30, 2008, unrecognized compensation expense related to non-performance based stock-settled SARs totaled approximately $0.2 million, which will be recognized over a weighted average period of 10.2 months. For a summary of transactions during

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2008 involving non-performance based stock-settled SARs for all plans, refer to Note E Capitalization and Short-Term Borrowings.

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

| | Year Ended September 30, 2007 |
|---|---|
| Risk Free Interest Rate | 4.53% |
| Expected Life (Years) | 7.0 |
| Expected Volatility | 17.55% |
| Expected Dividend Yield (Quarterly) | 0.73% |

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

For grants during the year ended September 30, 2007, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

***Performance Based Stock-settled SARs***

There were no performance based stock-settled SARs exercised during the years ended September 30, 2008, 2007 and 2006 as none of the performance based stock-settled SARs granted have vested. There were 321,000 performance based stock-settled SARs granted during 2008. The weighted average grant date fair value of performance based stock-settled SARs granted in 2008 is $9.06 per share. There were no performance based stock-settled SARs granted during 2007 or 2006. For the years ended September 30, 2008, 2007 and 2006, there were no performance based stock-settled SARs that became fully vested. As of September 30, 2008, unrecognized compensation expense related to performance based stock-settled SARs totaled approximately $1.9 million, which will be recognized over a weighted average period of 1.1 years. For a summary of transactions during 2008 involving performance based stock-settled SARs for all plans, refer to Note E Capitalization and Short-Term Borrowings.

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

| | Year Ended September 30, 2008 |
|---|---|

| | |
|---|---|
| Risk Free Interest Rate | 3.78% |
| Expected Life (Years) | 7.25 |
| Expected Volatility | 17.69% |
| Expected Dividend Yield (Quarterly) | 0.64% |

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

For grants during the year ended September 30, 2008, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***Restricted Share Awards***

The weighted average fair value of restricted share awards granted in 2008, 2007 and 2006 is $48.41 per share, $40.18 per share and $34.94 per share, respectively. As of September 30, 2008, unrecognized compensation expense related to restricted share awards totaled approximately $1.6 million, which will be recognized over a weighted average period of 2.5 years. For a summary of transactions during 2008 involving restricted share awards, refer to Note E Capitalization and Short-Term Borrowings.

During 2006, a modification was made to a restricted share award involving one employee. The modification accelerated the vesting date of 4,000 shares from December 7, 2006 to July 1, 2006. The incremental compensation expense, totaling approximately $32,000, was included with the total stock-based compensation expense for the year ended September 30, 2006.

***New Accounting Pronouncements***

In September 2006, the FASB issued SFAS 157, Fair Value Measurements . SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement 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. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. In accordance with FASB Staff Position FAS No. 157-2, SFAS 157 is effective for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis as of the Company s first quarter of fiscal 2009. The same FASB Staff Position delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value on a recurring basis, until the Company s first quarter of fiscal 2010. The Company does not expect that SFAS 157 will have a significant impact on its consolidated financial statements.

In September 2006, the FASB also issued SFAS 158, Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans (an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R). SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan s assets and obligations that determine its funded status be measured as of the end of the Company s fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date. At September 30, 2007, in order to recognize the funded status of its pension and post-retirement benefit plans in accordance with SFAS 158, the Company recorded additional liabilities or reduced assets by a cumulative amount of $78.7 million ($71.1 million net of deferred tax benefits recognized for the portion recorded as an increase to Accumulated Other Comprehensive Loss). Of the $71.1 million recognized, $61.9 million was recorded as an increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments, $12.5 million (net of deferred tax benefits of $7.6 million) was recorded as an increase to Accumulated Other Comprehensive Loss, and $3.3 million was recorded as an increase to Other

Regulatory Liabilities in the Company s Utility segment. The Company has recorded amounts to Other Regulatory Assets or Other Regulatory Liabilities in the Utility and Pipeline and Storage segments in accordance with the provisions of SFAS 71. The Company, in those segments, has certain regulatory commission authorizations, which allow the Company to defer as a regulatory asset or liability the difference between pension and post-retirement benefit costs as calculated in accordance with SFAS 87 and SFAS 106 and what is collected in rates. Refer to Note G Retirement Plan and Other Post-Retirement Benefits for further disclosures regarding the impact of SFAS 158 on the Company s consolidated financial statements.

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

In February 2007, the FASB issued SFAS 159, The Fair Value Option for Financial Assets and Financial Liabilities Including an Amendment of SFAS 115. SFAS 159 permits entities to choose to measure many financial instruments at fair value that are not otherwise required to be measured at fair value under GAAP. A company that elects the fair value option for an eligible item will be required to recognize in current earnings any changes in that item s fair value in reporting periods subsequent to the date of adoption. SFAS 159 is effective as of the Company s first quarter of fiscal 2009. The Company does not plan to elect the fair value measurement option for any of its financial instruments other than those that are already being measured at fair value.

In December 2007, the FASB issued SFAS 141R, Business Combinations. SFAS 141R will significantly change the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under SFAS 141R, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. SFAS 141R is effective as of the Company s first quarter of fiscal 2010.

In December 2007, the FASB issued SFAS 160, Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. SFAS 160 is effective as of the Company s first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued SFAS 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133. SFAS 161 requires entities to provide enhanced disclosures related to an entity s derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity s financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. SFAS 161 is effective as of the Company s second quarter of fiscal 2009. The Company is currently evaluating the impact that the adoption of SFAS 161 will have on its disclosures in the notes to the consolidated financial statements.

**Note B Asset Retirement Obligations**

The Company accounts for asset retirement obligations in accordance with the provisions of SFAS 143. SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset.

As previously disclosed, the Company follows the full cost method of accounting for its exploration and production costs. Upon the adoption of SFAS 143 on October 1, 2002, the Company recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment s crude oil and natural gas wells and capitalized such costs in property, plant and equipment (i.e. the full cost pool). Prior to the adoption of SFAS 143, plugging and abandonment costs were accounted for solely through the Company s units-of-production depletion calculation. An estimate of such costs was added to the depletion base, which also included capitalized costs in the full cost pool and estimated future expenditures to be incurred in developing proved reserves. With the adoption of SFAS 143, plugging and abandonment costs are already included in capitalized costs and the units-of-production depletion calculation has been modified to exclude from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

The full cost method of accounting provides a limit to the amount of costs that can be capitalized in the full cost pool. This limit is referred to as the full cost ceiling. Prior to the adoption of SFAS 143, in calculating the full

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

cost ceiling, the Company reduced the future net cash flows from proved oil and gas reserves by the estimated plugging and abandonment costs. Such future net cash flows would then be compared to capitalized costs in the full cost pool, with any excess capitalized costs being expensed. With the adoption of SFAS 143, since the full cost pool now includes an amount associated with plugging and abandoning the wells, the calculation of the full cost ceiling has been changed so that future net cash flows from proved oil and gas reserves are no longer reduced by the estimated plugging and abandonment costs.

On September 30, 2006, the Company adopted FIN 47, an interpretation of SFAS 143. FIN 47 provides clarification of the term conditional asset retirement obligation as used in SFAS 143, defined as a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. Under this standard, if the fair value of a conditional asset retirement obligation can be reasonably estimated, a company must record a liability and a corresponding asset for the conditional asset retirement obligation representing the present value of that obligation at the date the obligation was incurred. FIN 47 also serves to clarify when a company would have sufficient information to reasonably estimate the fair value of a conditional asset retirement obligation.

Upon the adoption of FIN 47, the Company recorded future asset retirement obligations associated with the plugging and abandonment of natural gas storage wells in the Pipeline and Storage segment and the removal of asbestos and asbestos-containing material in various facilities in the Utility and Pipeline and Storage segments. The Company also identified asset retirement obligations for certain costs connected with the retirement of distribution mains and services pipeline systems in the Utility segment and with the transmission mains and other components in the pipeline systems in the Pipeline and Storage segment. These retirement costs within the distribution and transmission systems are primarily for the capping and purging of pipe, which are generally abandoned in place when retired, as well as for the clean-up of PCB contamination associated with the removal of certain pipe.

As a result of the implementation of FIN 47 as of September 30, 2006, the Company recorded additional asset retirement obligations of $23.2 million and corresponding long-lived plant assets, net of accumulated depreciation, of $3.5 million. These assets will be depreciated over their respective remaining depreciable life. The remaining $19.7 million represents the cumulative accretion and depreciation of the asset retirement obligations that would have been recognized if this interpretation had been in effect at the inception of the obligations. Of this amount, the Company recorded an increase to regulatory assets of $9.0 million and a reduction to cost of removal regulatory liability of $10.7 million. The cost of removal regulatory liability represents amounts collected from customers through depreciation expense in the Company s Utility and Pipeline and Storage segments. These removal costs are not a legal retirement obligation in accordance with SFAS 143. Rather, they represent a regulatory liability. However, SFAS 143 requires that such costs of removal be reclassified from accumulated depreciation to other regulatory liabilities. At September 30, 2008 and 2007, the costs of removal reclassified to other regulatory liabilities amounted to $103.1 million and $91.2 million, respectively.

A reconciliation of the Company s asset retirement obligation calculated in accordance with SFAS 143 is shown below:

| | Year Ended September 30 | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |

| | (Thousands) | | |
|---|---|---|---|
| Balance at Beginning of Year | $ 75,939 | $ 77,392 | $ 41,411 |
| Additions Adoption of FIN 47 | | | 23,234 |
| Liabilities Incurred and Revisions of Estimates | 18,739 | (932) | 11,244 |
| Liabilities Settled | (6,871) | (6,108) | (1,303) |
| Accretion Expense | 5,440 | 5,394 | 2,671 |
| Exchange Rate Impact | | 193 | 135 |
| Balance at End of Year | $ 93,247 | $ 75,939 | $ 77,392 |

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

## Note C Regulatory Matters

***Regulatory Assets and Liabilities***

The Company has recorded the following regulatory assets and liabilities:

| | At September 30 2008 | 2007 |
|---|---|---|
| | (Thousands) | |
| **Regulatory Assets(1):** | | |
| Pension and Other Post-Retirement Benefit Costs(2) (Note G) | $ 147,909 | $ 98,787 |
| Recoverable Future Taxes (Note D) | 82,506 | 83,954 |
| Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A) | 37,708 | 14,769 |
| Environmental Site Remediation Costs(2) (Note H) | 22,530 | 20,738 |
| Asset Retirement Obligations(2) (Note B) | 8,155 | 8,315 |
| Unamortized Debt Expense (Note A) | 7,524 | 8,470 |
| Recoverable Worker Compensation Expense(2) | 4,518 | 4,445 |
| Other(2) | 6,475 | 5,292 |
| Total Regulatory Assets | 317,325 | 244,770 |
| **Regulatory Liabilities**: | | |
| Cost of Removal Regulatory Liability (Note B) | 103,100 | 91,226 |
| Pension and Other Post-Retirement Benefit Costs(3) (Note G) | 42,994 | 21,676 |
| Tax Benefit on Medicare Part D Subsidy(3) | 23,502 | 19,147 |
| New York Rate Settlements(3) | 19,012 | 27,964 |
| Taxes Refundable to Customers (Note D) | 18,449 | 14,026 |
| Deferred Insurance Proceeds(3) | 3,933 | 7,422 |
| Amounts Payable to Customers (See Regulatory Mechanisms in Note A) | 2,753 | 10,409 |
| Other(3) | 2,492 | 450 |
| Total Regulatory Liabilities | 216,235 | 192,320 |
| Net Regulatory Position | $ 101,090 | $ 52,450 |

(1) The Company recovers the cost of its regulatory assets but, with the exception of Unrecovered Purchased Gas Costs, does not earn a return on them.

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

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

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

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

***New York Rate Settlements***

With respect to utility services provided in New York, the Company has entered into rate settlements approved by the NYPSC. The rate settlements have given rise to several significant liabilities, which are described as follows:

Gross Receipts Tax Over-Collections In accordance with NYPSC policies, Distribution Corporation deferred the difference between the revenues it collects under a New York State gross receipts tax surcharge and its actual New York State income tax expense. Distribution Corporation s cumulative gross receipts tax revenues exceeded its New York State income tax expense, resulting in a regulatory liability at September 30, 2008 and 2007 of $4.1 million and $6.7 million, respectively. Under the terms of its 2005 rate agreement, Distribution Corporation has been passing back that regulatory liability to rate payers since August 1, 2005. Further, the gross receipts tax surcharge that gave rise to the regulatory liability was eliminated from Distribution Corporation s tariff (New York State income taxes are now recovered as a component of base rates).

Cost Mitigation Reserve ( CMR ) The CMR is a regulatory liability that can be used to offset certain expense items specified in Distribution Corporation s rate settlements. The source of the CMR was principally the accumulation of certain refunds from upstream pipeline companies. During 2005, under the terms of the 2005 rate agreement, Distribution Corporation transferred the remaining balance in a generic restructuring reserve (which had been established in a prior rate settlement) and the balances it had accumulated under various earnings sharing mechanisms to the CMR. The balance in the CMR at September 30, 2008 and 2007 amounted to $0.3 million and $7.4 million, respectively.

Other The 2005 agreement also established a reserve to fund area development projects. The balance in the area development projects reserve at September 30, 2008 and 2007 amounted to $3.0 million and $3.6 million, respectively (Distribution Corporation established the reserve at September 30, 2005 by transferring $3.8 million from the CMR discussed above). Various other regulatory liabilities have also been created through the New York rate settlements and amounted to $11.6 million and $10.3 million at September 30, 2008 and 2007, respectively.

***Tax Benefit on Medicare Part D Subsidy***

The Company has established a regulatory liability for the tax benefit it will receive under the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act). The Act provides a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In the Company s Utility and Pipeline and Storage segments, the ratepayer funds the Company s post-retirement benefit plans. As such, any tax benefit received under the Act must be flowed-through to the ratepayer. Refer to Note G Retirement Plan and Other Post-Retirement Benefits for further discussion of the Act and its impact on the Company.

***Deferred Insurance Proceeds***

The Company, in its Utility and Pipeline and Storage segments, has deferred environmental insurance settlement proceeds amounting to $3.9 million and $7.4 million at September 30, 2008 and 2007, respectively. Such proceeds have been deferred as a regulatory liability to be applied against any future environmental claims that may be incurred. The proceeds have been classified as a regulatory liability in recognition of the fact that ratepayers funded the premiums on the former insurance policies.

***Recoverable Worker Compensation Expense***

The Company has established a liability in its Utility segment in accordance with the provisions of SFAS 112 for future worker compensation liabilities. Such amounts have been deferred as a regulatory asset because the Company is allowed to recover worker compensation expense in rates.

## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

### Note D Income Taxes

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| Current Income Taxes | | | |
| Federal | $ 75,079 | $ 99,608 | $ 65,593 |
| State | 20,257 | 21,700 | 13,511 |
| Foreign | 90 | 22 | 2,212 |
| Deferred Income Taxes | | | |
| Federal | 56,668 | 39,340 | 19,111 |
| State | 15,828 | 10,751 | 9,024 |
| Foreign | | 2,756 | (33,365) |
| | 167,922 | 174,177 | 76,086 |
| Deferred Investment Tax Credit | (697) | (697) | (697) |
| Total Income Taxes | $ 167,225 | $ 173,480 | $ 75,389 |
| Presented as Follows: | | | |
| Other Income | $ (697) | $ (697) | $ (697) |
| Income Tax Expense Continuing Operations | 167,922 | 131,813 | 108,245 |
| Discontinued Operations | | | |
| Income From Operations | | 2,792 | (32,159) |
| Gain on Disposal | | 39,572 | |
| Total Income Taxes | $ 167,225 | $ 173,480 | $ 75,389 |

The U.S. and foreign components of income (loss) before income taxes are as follows:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| U.S. | $ 435,982 | $ 496,074 | $ 293,887 |
| Foreign | (29) | 14,861 | (80,407) |

| | | | |
|---|---|---|---|
| | $ 435,953 | $ 510,935 | $ 213,480 |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

| | Year Ended September 30 2008 | 2007 (Thousands) | 2006 |
|---|---|---|---|
| Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35% | $ 152,584 | $ 178,827 | $ 74,718 |
| Increase in Taxes Resulting from: | | | |
| State Income Taxes | 23,455 | 21,093 | 14,648 |
| Foreign Tax Differential | 69 | (20,980) | (3,718) |
| Reversal of Capital Loss Valuation Allowance | | | (2,877) |
| Miscellaneous | (8,883) | (5,460) | (7,382) |
| Total Income Taxes | $ 167,225 | $ 173,480 | $ 75,389 |

The foreign tax differential amount shown above for 2007 includes tax effects relating to the gain on disposition of a foreign subsidiary. Also, the foreign tax differential amount shown above for 2006 includes a $5.1 million deferred tax benefit relating to additional future tax deductions forecasted in Canada. The miscellaneous amount shown above for 2006 includes a net reversal of $3.2 million relating to a tax contingency reserve.

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

| | At September 30 2008 | 2007 (Thousands) |
|---|---|---|
| Deferred Tax Liabilities: | | |
| Property, Plant and Equipment | $ 673,313 | $ 612,648 |
| Pension and Other Post-Retirement Benefit Costs SFAS 158 | 43,340 | 21,892 |
| Other | 55,391 | 39,724 |
| Total Deferred Tax Liabilities | 772,044 | 674,264 |
| Deferred Tax Assets: | | |
| Pension and Other Post-Retirement Benefit Costs SFAS 158 | (43,340) | (21,892) |
| Other | (92,461) | (85,566) |
| Total Deferred Tax Assets | (135,801) | (107,458) |

| | | |
|---|---|---|
| Total Net Deferred Income Taxes | $ 636,243 | $ 566,806 |
| Presented as Follows: | | |
| Net Deferred Tax Liability/(Asset) Current | $ 1,871 | $ (8,550) |
| Net Deferred Tax Liability Non-Current | 634,372 | 575,356 |
| Total Net Deferred Income Taxes | $ 636,243 | $ 566,806 |

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $18.4 million and $14.0 million at September 30, 2008 and 2007, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $82.5 million and $84.0 million at September 30, 2008 and 2007, respectively.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company adopted FIN 48 on October 1, 2007. As of the date of adoption, a cumulative effect adjustment was recorded that resulted in a decrease to retained earnings of $0.4 million. Upon adoption, the unrecognized tax benefits were $1.7 million, all of which would impact the effective tax rate (net of federal benefit) if recognized.

A tabular reconciliation of the change in unrecognized tax benefits for the twelve months ended September 30, 2008 is as follows:

| | Amount (thousands) |
|---|---|
| Opening Balance of Unrecognized Tax Benefits October 1, 2007 | $ 1,700 |
| Gross Increase Tax Positions in Prior Periods | |
| Gross Decrease Tax Positions in Prior Periods | |
| Gross Increase Tax Positions in Current Periods | |
| Gross Decrease Tax Positions in Current Periods | |
| Decrease in Unrecognized Tax Benefits Related to Tax Settlements | |
| Reduction to Unrecognized Tax Benefits Due to Lapse of Statute of Limitations | |
| Ending Balance of Unrecognized Tax Benefits September 30, 2008 | $ 1,700 |

Within the next twelve months, the Company believes it is reasonably possible that the total amount of unrecognized tax benefits may be eliminated. This potential decrease in the amount of unrecognized tax benefits is associated with the anticipated completion of state income tax audits for various prior years.

The Company recognizes estimated interest payable relating to income taxes in Other Interest Expense and estimated penalties relating to income taxes in Other Income. The Company has accrued interest of $0.5 million through September 30, 2008 and has not accrued any penalties.

The Company files U.S. federal and various state income tax returns. The Internal Revenue Service (IRS) is currently conducting an examination of the Company for fiscal 2008 in accordance with the Compliance Assurance Process ( CAP ). The CAP audit employs a real time review of the Company s books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. While the federal statute of limitations remains open for fiscal 2005 and later years, IRS examinations for fiscal 2007 and prior years have been completed and the Company believes such years are effectively settled.

For the major states in which the various subsidiary companies operate, the earliest tax year open for examination is as follows:

| | |
|---|---|
| New York | Fiscal 2002 |
| Pennsylvania | Fiscal 2003 |
| California | Fiscal 2004 |

| | |
|---|---|
| Texas | Fiscal 2004 |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**Note E Capitalization and Short-Term Borrowings**

***Summary of Changes in Common Stock Equity***

| | Common Stock Shares | Common Stock Amount | Paid In Capital | Earnings Reinvested in the Business | Accumulated Other Comprehensive Income (Loss) |
|---|---|---|---|---|---|
| | (Thousands, except per share amounts) | | | | |
| Balance at September 30, 2005 | 84,357 | $ 84,357 | $ 529,834 | $ 813,020 | $ (197,628) |
| Net Income Available for Common Stock | | | | 138,091 | |
| Dividends Declared on Common Stock ($1.18 Per Share) | | | | (98,829) | |
| Other Comprehensive Income, Net of Tax | | | | | 228,044 |
| Share-Based Payment Expense(2) | | | 1,705 | | |
| Common Stock Issued Under Stock and Benefit Plans(1) | 1,572 | 1,572 | 28,564 | | |
| Share Repurchases | (2,526) | (2,526) | (16,373) | (66,269) | |
| Balance at September 30, 2006 | 83,403 | 83,403 | 543,730 | 786,013 | 30,416 |
| Net Income Available for Common Stock | | | | 337,455 | |
| Dividends Declared on Common Stock ($1.22 Per Share) | | | | (101,496) | |
| Other Comprehensive Loss, Net of Tax | | | | | (24,137) |
| Adjustment to Recognize the Funded Position of the Pension and Other Post-Retirement Benefit Plans | | | | | (12,482) |
| Share-Based Payment Expense(2) | | | 3,727 | | |
| Common Stock Issued Under Stock and Benefit Plans(1) | 1,367 | 1,367 | 30,193 | | |
| Share Repurchases | (1,309) | (1,309) | (8,565) | (38,196) | |
| Balance at September 30, 2007 | 83,461 | 83,461 | 569,085 | 983,776 | (6,203) |
| Net Income Available for Common Stock | | | | 268,728 | |

| | | | | | |
|---|---|---|---|---|---|
| Dividends Declared on Common Stock ($1.27 Per Share) | | | | (103,523) | |
| Cumulative Effect of the Adoption of FIN 48 | | | | (406) | |
| Other Comprehensive Loss, Net of Tax | | | | | 9,166 |
| Share-Based Payment Expense(2) | | | 2,332 | | |
| Common Stock Issued Under Stock and Benefit Plans(1) | 854 | 854 | 33,335 | | |
| Share Repurchases | (5,194) | (5,194) | (37,036) | (194,776) | |
| Balance at September 30, 2008 | 79,121 | $ 79,121 | $ 567,716 | $ 953,799(3) | $ 2,963 |

(1) Paid in Capital includes tax benefits of $16.3 million, $13.7 million and $6.5 million for September 30, 2008, 2007 and 2006, respectively, associated with the exercise of stock options.

(2) As of October 1, 2005, Paid in Capital includes compensation costs associated with stock option, stock-settled SARs and/or restricted stock awards, in accordance with SFAS 123R. The expense is included within Net Income Available For Common Stock, net of tax benefits.

(3) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2008, $808.8 million of accumulated earnings was free of such limitations.

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

*Common Stock*

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

During 2008, the Company issued 890,944 original issue shares of common stock as a result of stock option exercises and 25,000 original issue shares for restricted stock awards (non-vested stock as defined in SFAS 123R). Holders of stock options or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During 2008, 72,205 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

The Company also has a director stock program under which it issues shares of Company common stock to the non-employee directors of the Company who receive compensation under the Company s Retainer Policy for Non-Employee Directors, as partial consideration for their services as directors. Under this program, the Company issued 9,600 original issue shares of common stock during 2008.

In December 2005, the Company s Board of Directors authorized the Company to implement a share repurchase program, whereby the Company may 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. Under this new authorization, the Company repurchased 1,028,981 shares for $46.0 million through September 17, 2008. The Company stopped repurchasing shares after September 17, 2008 in light of the unsettled nature of the credit markets. However, such repurchases may be made in the future if conditions improve. All share repurchases mentioned above were funded with cash provided by operating activities and/or through the use of the Company s lines of credit.

*Shareholder Rights Plan*

In 1996, the Company s Board of Directors adopted a shareholder rights plan (Plan). The Plan has been amended five times since it was adopted and is now embodied in an Amended and Restated Rights Agreement effective July 11, 2008, which is an Exhibit to this Annual Report and Form 10-K.

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

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

The Rights become exercisable upon the occurrence of a Distribution Date as described below, but after a Distribution Date Rights that are owned by an Acquiring Person will be null and void. At any time following a

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

Distribution Date, each holder of a Right may exercise its right to receive a number of shares of common stock determined in accordance with a Plan formula that is based on the current market value of the Company s common stock. Under certain circumstances, each holder of a Right may instead receive other property of the Company. However, the Rights are subject to redemption or exchange by the Company prior to their exercise as described below.

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

In certain situations after a person or group has acquired beneficial ownership of 10% or more of the total voting power of the Company s stock as described above, each holder of a Right will have the right to exercise its Rights to receive a number of shares of common stock determined in accordance with a Plan formula based on the current market value of the Company s common stock, or other property of the Company. These situations would arise if the Company is acquired in a merger or other business combination or if 50% or more of the Company s assets or earning power are sold or transferred.

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

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

***Stock Option and Stock Award Plans***

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, stock-settled SARs, restricted stock, performance units or performance shares. Stock options and stock-settled SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no option or stock-settled SAR is exercisable less than one year or more than ten years after the date of each grant.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

| | Number of Shares Subject to Option | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life (Years) | Aggregate Intrinsic Value (In thousands) |
|---|---|---|---|---|
| Outstanding at September 30, 2007 | 7,360,041 | $ 25.89 | | |
| Granted in 2008 | | $ | | |
| Exercised in 2008 | (890,944) | $ 23.78 | | |
| Forfeited in 2008 | (4,400) | $ 27.97 | | |
| Outstanding at September 30, 2008 | 6,464,697 | $ 26.17 | 3.11 | $ 103,477 |
| Option shares exercisable at September 30, 2008 | 6,337,697 | $ 25.94 | 3.02 | $ 102,909 |
| Option shares available for future grant at September 30, 2008(1) | 745,797 | | | |

(1) Including shares available for stock-settled SARs and restricted stock grants.

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

| | Number of Shares Subject To Option | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life (Years) | Aggregate Intrinsic Value (In thousands) |
|---|---|---|---|---|
| Outstanding at September 30, 2007 | 50,000 | $ 41.20 | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Granted in 2008 | | $ | | | | |
| Exercised in 2008 | | $ | | | | |
| Forfeited in 2008 | | $ | | | | |
| Outstanding at September 30, 2008 | 50,000 | $ | 41.20 | 8.45 | $ | 49 |
| Stock-settled SARs exercisable at September 30, 2008 | | | | | $ | |

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

| | Number of Shares Subject To Option | | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life (Years) | | Aggregate Intrinsic Value (In thousands) |
|---|---|---|---|---|---|---|
| Outstanding at September 30, 2007 | | $ | | | | |
| Granted in 2008 | 321,000 | $ | 48.46 | | | |
| Exercised in 2008 | | $ | | | | |
| Forfeited in 2008 | (6,000) | $ | 58.99 | | | |
| Outstanding at September 30, 2008 | 315,000 | $ | 48.26 | 9.42 | $ | (1,914) |
| Stock-settled SARs exercisable at September 30, 2008 | | | | | $ | |

***Restricted Share Awards***

Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. The market value of restricted stock on the date of the award is recorded as compensation expense over the vesting period. Certificates for shares of restricted stock awarded under the Company s stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective.

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

| | Number of Restricted Share Awards | | Weighted Average Fair Value per Award |
|---|---|---|---|
| Restricted Share Awards Outstanding at September 30, 2007 | 36,328 | $ | 38.16 |
| Granted in 2008 | 25,000 | $ | 48.41 |
| Vested in 2008 | (2,500) | $ | 34.94 |
| Forfeited in 2008 | | $ | |

| | | | |
|---|---|---|---|
| Restricted Share Awards Outstanding at September 30, 2008 | 58,828 | $ | 42.65 |

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2008 will lapse as follows: 2009 2,500 shares; 2010 28,828 shares; 2011 2,500 shares; 2012 5,000 shares; 2013 5,000 shares; 2014 5,000 shares; 2015 5,000 shares; and 2016 5,000 shares.

***Redeemable Preferred Stock***

As of September 30, 2007, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

***Long-Term Debt***

The outstanding long-term debt is as follows:

| | At September 30 2008 | 2007 |
|---|---|---|
| | (Thousands) | |
| Medium-Term Notes(1): | | |
| 6.0% to 7.50% due March 2009 to June 2025 | $ 549,000 | $ 749,000 |
| Notes(1): | | |
| 5.25% to 6.5% due March 2013 to September 2022(2) | 550,000 | 250,000 |
| | 1,099,000 | 999,000 |
| Other Notes: | | |
| Unsecured | | 24 |
| Total Long-Term Debt | 1,099,000 | 999,024 |
| Less Current Portion | 100,000 | 200,024 |
| | $ 999,000 | $ 799,000 |

(1) The medium-term notes and notes are unsecured.

(2) In April 2008, the Company issued $300.0 million of 6.50% senior, unsecured notes in a private placement exempt from registration under the Securities Act of 1933. The notes have a term of 10 years, with a maturity date in April 2018. The holders of the notes may require the Company to repurchase their notes in the event of a change in control at a price equal to 101% of the principal amount. In addition, the Company is required to either offer to exchange the notes for substantially similar notes registered under the Securities Act of 1933 or, in certain circumstances, register the resale of the notes. The Company used $200.0 million of the proceeds from the sale of the notes to refund $200.0 million of 6.303% medium-term notes that subsequently matured on May 27, 2008.

As of September 30, 2008, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $100.0 million in 2009, zero in 2010, $200.0 million in 2011, $150.0 million in 2012, $250.0 million in 2013, and $399.0 million thereafter.

***Short-Term Borrowings***

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. As for the former, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These uncommitted credit lines, which aggregate to $420.0 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 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 that extends through September 30, 2010.

At September 30, 2008 and 2007, the Company had no outstanding short-term notes payable to banks or commercial paper.

## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***Debt Restrictions***

Under the Company s committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2010. At September 30, 2008, the Company s debt to capitalization ratio (as calculated under the facility) was .41. The constraints specified in the committed credit facility would permit an additional $1.88 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company s debt to capitalization ratio would exceed .65. If a downgrade in any of the Company s credit ratings were to occur, access to the commercial paper markets might not be possible. However, the Company expects that it could borrow under its committed credit facility, uncommitted bank lines of credit or rely upon other liquidity sources, including cash provided by operations.

Under the Company s existing indenture covenants, at September 30, 2008, 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 1974 indenture pursuant to which $199.0 million (or 18%) of the Company s long-term debt (as of September 30, 2008) 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 or 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 fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2008, the Company had no debt outstanding under the committed credit facility.

### Note F Financial Instruments

***Fair Values***

The fair market value of the Company s long-term debt is estimated based on quoted market prices of similar issues having the same remaining maturities, redemption terms and credit ratings. Based on these criteria, the fair market value of long-term debt, including current portion, was as follows:

| | At September 30 | | | |
|---|---|---|---|---|
| | 2008 Carrying | 2008 Fair | 2007 Carrying | 2007 Fair |

| | Amount | Value | Amount | Value |
|---|---|---|---|---|
| | | (Thousands) | | |
| Long-Term Debt | $ 1,099,000 | $ 1,027,098 | $ 999,024 | $ 1,024,417 |

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay.

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

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

***Other Investments***

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance contracts amounted to $53.6 million and $54.7 million at September 30, 2008 and 2007, respectively. The fair value of the equity mutual fund was $12.4 million and $14.7 million at September 30, 2008 and 2007, respectively. The gross unrealized loss on this equity mutual fund was $(1.0) million at September 30, 2008. The equity mutual fund was in a gross unrealized gain position of $2.2 million at September 30, 2007. The fair value of the stock of an insurance company was $14.5 million and $16.3 million at September 30, 2008 and 2007, respectively. The gross unrealized gain on this stock was $12.1 million and $13.8 million at September 30, 2008 and 2007, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

***Derivative Financial Instruments***

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with the fluctuations in the price of natural gas and crude oil. These instruments include price swap agreements, no cost collars and futures contracts.

Under the price swap agreements, the Company receives monthly payments from (or makes payments to) other parties based upon the difference between a fixed price and a variable price as specified by the agreement. The variable price is either a crude oil or natural gas price quoted on the NYMEX or a quoted natural gas price in various national natural gas publications. The majority of these derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment and the All Other category. The Energy Marketing segment accounts for these derivative financial instruments as fair value hedges and uses them to hedge against falling prices, a risk to which they are exposed on their fixed price gas purchase commitments. The Energy Marketing segment also uses these derivative financial instruments to hedge against rising prices, a risk to which they are exposed on their fixed price sales commitments. At September 30, 2008, the Company had natural gas price swap agreements covering a notional amount of 15.1 Bcf extending through 2011 at a weighted average fixed rate of $9.69 per Mcf. Of this amount, 0.9 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $9.64 per Mcf. The remaining 14.2 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $9.69 per Mcf. At September 30, 2008, the Company would have received a net $20.3 million to terminate the price swap agreements. The Company also had crude oil price swap agreements covering a notional amount of 1,920,000 bbls extending through 2011 at a weighted average fixed rate of $90.50 per bbl. At September 30, 2008, the Company would have had to pay a net $0.8 million to terminate the price swap agreements. The Energy Marketing segment also used natural gas swaps to hedge basis risk on their fixed price purchase commitments. At September 30, 2008, the Company had natural gas swap agreements covering 1.4 Bcf at a weighted average fixed rate of $0.47 per Mcf. These are treated as fair value hedges and the Company would have had to pay $0.2 million at September 30, 2008 to terminate the agreements.

At September 30, 2008, the Company had long (purchased) futures contracts covering 9.1 Bcf of gas extending through 2012 at a weighted average contract price of $9.24 per Mcf. They are accounted for as fair value hedges and are used by the Company s Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with residential, commercial and industrial customers. The Company would have had to pay $9.9 million to terminate these futures contracts at September 30, 2008.

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

At September 30, 2008, the Company had short (sold) futures contracts covering 6.7 Bcf of gas extending through 2010 at a weighted average contract price of $11.02 per Mcf. Of this amount, 3.5 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Energy Marketing segment. The remaining 3.2 Bcf is accounted for as fair value hedges used to hedge against falling prices on their fixed price gas purchasing commitments and hedge against decreases in natural gas prices associated with the eventual sale of gas in storage. The Company would have received $18.6 million to terminate these futures contracts at September 30, 2008.

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 an ongoing basis monitors counterparty credit exposure. Management has obtained guarantees from many of the parent companies of the respective counterparties to its derivative financial instruments. At September 30, 2008, the Company had eleven counterparties for its over the counter derivative financial instruments and no individual counterparty represented greater than 42% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company s total over the counter volumes hedged). The Company recorded a $0.6 million reduction to the fair market value of its derivative contracts that are in a gain position based on its assessment of counterparty credit risk. This credit reserve was determined by applying default probabilities to the anticipated cash flows that the Company is expecting from its counterparties.

**Note G Retirement Plan and Other Post-Retirement Benefits**

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan) that covers approximately 65% of the employees of the Company. The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Employees hired after June 30, 2003 are eligible for a Retirement Savings Account benefit provided under the Company s defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account benefit have been $0.6 million through September 30, 2008 (with $0.2 million, $0.2 million and $0.1 million of costs occurring in 2008, 2007 and 2006, respectively). Costs associated with the Company s contributions to the Tax-Deferred Savings Plans were $4.0 million, $4.1 million, and $4.1 million for the years ended September 30, 2008, 2007 and 2006, respectively.

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

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

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The expected return on plan assets, a component of net periodic benefit cost shown in the tables below, is applied to the market-related value of plan assets. The market-related value of plan assets is equal to market value as of the measurement date.

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and other post-retirement benefits are shown in the tables below. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is June 30, 2008, 2007 and 2006, respectively.

| | Retirement Plan Year Ended September 30 | | | Other Post-Retirement Benefits Year Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2008** | **2007** | **2006** | **2008** | **2007** | **2006** |
| | (Thousands) | | | | | |
| **Change in Benefit Obligation** | | | | | | |
| Benefit Obligation at Beginning of Period | $ 742,519 | $ 732,207 | $ 825,204 | $ 444,545 | $ 445,931 | $ 546,273 |
| Service Cost | 12,597 | 12,898 | 16,416 | 5,104 | 5,614 | 8,029 |
| Interest Cost | 44,949 | 44,350 | 40,196 | 27,081 | 27,198 | 26,804 |
| Plan Participants Contributions | | | | 1,990 | 1,566 | 1,559 |
| Retiree Drug Subsidy Receipts | | | | 1,532 | 1,325 | |
| Amendments(1) | | | | (31,874) | | |
| Actuarial (Gain) Loss | (34,189) | (2,986) | (108,112) | (14,390) | (14,450) | (115,052) |
| Benefits Paid | (46,817) | (43,950) | (41,497) | (22,443) | (22,639) | (21,682) |
| **Benefit Obligation at End of Period** | $ 719,059 | $ 742,519 | $ 732,207 | $ 411,545 | $ 444,545 | $ 445,931 |
| **Change in Plan Assets** | | | | | | |
| Fair Value of Assets at Beginning of Period | $ 765,144 | $ 664,521 | $ 616,462 | $ 412,371 | $ 325,624 | $ 271,636 |
| Actual Return on Plan Assets | (39,206) | 119,662 | 68,649 | (43,478) | 65,552 | 34,785 |
| Employer Contributions | 3,817 | 16,488 | 20,907 | 29,200 | 42,268 | 39,326 |
| Employer Contributions During Period from Measurement Date to Fiscal Year End | 12,151 | 8,423 | | | | |
| Plan Participants Contributions | | | | 1,990 | 1,566 | 1,559 |
| Benefits Paid | (46,817) | (43,950) | (41,497) | (22,443) | (22,639) | (21,682) |

| | | | | | | |
|---|---|---|---|---|---|---|
| **Fair Value of Assets at End of Period** | $ 695,089 | $ 765,144 | $ 664,521 | $ 377,640 | $ 412,371 | $ 325,624 |
| **Reconciliation of Funded Status** | | | | | | |
| Funded Status | $ (23,970) | $ 22,625 | $ (67,686) | $ (33,905) | $ (32,174) | $ (120,307) |
| Unrecognized Net Actuarial Loss | | | 107,626 | | | 54,487 |
| Unrecognized Transition Obligation | | | | | | 49,890 |
| Unrecognized Prior Service Cost | | | 7,185 | | | 12 |
| Net Amount Recognized at End of Period | $ (23,970) | $ 22,625 | $ 47,125 | $ (33,905) | $ (32,174) | $ (15,918) |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

| | Retirement Plan Year Ended September 30 | | | Other Post-Retirement Benefits Year Ended September 30 | | |
|---|---|---|---|---|---|---|
| | **2008** | **2007** | **2006** | **2008** | **2007** | **2006** |
| | (Thousands) | | | | | |
| **Amounts Recognized in the Balance Sheets Consist of:** | | | | | | |
| Accrued Benefit Liability | $ (23,970) | $ | $ | $ (54,939) | $ (70,555) | $ (32,918) |
| Prepaid Benefit Cost | | 22,625 | 47,125 | 21,034 | 38,381 | 17,000 |
| Intangible Assets | | | | | | |
| Accumulated Other Comprehensive Loss from Additional Minimum Pension Liability Adjustment (Pre-Tax) | | | | | | |
| Net Amount Recognized at End of Period | $ (23,970) | $ 22,625 | $ 47,125 | $ (33,905) | $ (32,174) | $ (15,918) |
| **Weighted Average Assumptions Used to Determine Benefit Obligation at September 30** | | | | | | |
| Discount Rate | 6.75% | 6.25% | 6.25% | 6.75% | 6.25% | 6.25% |
| Expected Return on Plan Assets | 8.25% | 8.25% | 8.25% | 8.25% | 8.25% | 8.25% |
| Rate of Compensation Increase | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| **Components of Net Periodic Benefit Cost** | | | | | | |
| Service Cost | $ 12,598 | $ 12,898 | $ 16,416 | $ 5,104 | $ 5,614 | $ 8,029 |
| Interest Cost | 44,949 | 44,350 | 40,196 | 27,081 | 27,198 | 26,804 |
| Expected Return on Plan Assets | (55,000) | (51,235) | (49,943) | (33,715) | (26,960) | (22,302) |
| Amortization of Prior Service Cost | 808 | 882 | 957 | 4 | 4 | 4 |
| Amortization of Transition Amount | | | | 7,127 | 7,127 | 7,127 |
| Recognition of Actuarial Loss(2) | 11,063 | 13,528 | 23,108 | 2,927 | 8,214 | 23,402 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Net Amortization and Deferral for Regulatory Purposes | 6,008 | 1,211 | (6,409) | 22,264 | 16,220 | (11,084) |
| Net Periodic Benefit Cost | $ 20,426 | $ 21,634 | $ 24,325 | $ 30,792 | $ 37,417 | $ 31,980 |
| Other Comprehensive (Income) Loss (Pre-Tax) Attributable to Change In Additional Minimum Liability Recognition | $ | $ | $ (165,914) | $ | $ | $ |
| Accumulated Other Comprehensive Loss (Pre-Tax) Attributable to Adoption of SFAS 158 | NA | $ 11,256 | NA | NA | $ 778 | NA |
| **Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30** | | | | | | |
| Discount Rate | 6.25% | 6.25% | 5.00% | 6.25% | 6.25% | 5.00% |
| Expected Return on Plan Assets | 8.25% | 8.25% | 8.25% | 8.25% | 8.25% | 8.25% |
| Rate of Compensation Increase | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(1) In Fiscal 2008, the Company passed an amendment, for most of the subsidiaries, which increased the participant contributions for active employees at the time of the amendment. This decreased the benefit obligation.

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

The Net Periodic Benefit Cost in the table above includes the effects of regulation. The Company recovers pension and other post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorizations. Certain of those commission authorizations established tracking mechanisms which allow the Company to record the difference between the amount of pension and other post-retirement benefit costs recoverable in rates and the amounts of such costs as determined under SFAS 87 and SFAS 106 as either a regulatory asset or liability, as appropriate. Any activity under the tracking mechanisms (including the amortization of pension and other post-retirement regulatory assets) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

In September 2006, the FASB issued SFAS 158, an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R. SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan s assets and obligations that determine its funded status be measured as of the end of Company s fiscal year, with limited exceptions. Under SFAS 158, certain previously unrecognized actuarial gains and losses, previously unrecognized prior service costs, and a previously unrecognized transition obligation are required to be recognized. These amounts were not required to be recorded on the Company s Consolidated Balance Sheet before the adoption of SFAS 158, but were instead amortized over a period of time. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 as of September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date. The incremental effects of adopting the provisions of SFAS 158 on the Company s Consolidated Balance Sheet at September 30, 2007 are presented in the table below:

| | Before Application of SFAS 158(1) | Consolidated SFAS 158 Impact (Thousands) | After Application of SFAS 158 |
|---|---|---|---|
| **Qualified Retirement Plan** | | | |
| Reduction in Prepaid Pension and Other Post-Retirement Benefit Costs | $ 51,612 | $ (28,987) | $ 22,625 |
| Increase in Other Regulatory Assets Related to SFAS 158 | $ | $ 17,731 | $ 17,731 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Reduction in Accumulated Other Comprehensive Income | $ | | $ | 7,008 | $ | 7,008 |
| Reduction in Deferred Income Taxes (under Deferred Credits) | $ | | $ | 4,248 | $ | 4,248 |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

| | Before Application of SFAS 158(1) | Consolidated SFAS 158 Impact (Thousands) | After Application of SFAS 158 |
|---|---|---|---|
| **Other Post-Retirement Benefits** | | | |
| Increase in Prepaid Pension and Other Post-Retirement Benefit Costs | $ 26,067 | $ 12,314 | $ 38,381 |
| Increase in Other Regulatory Assets Related to SFAS 158 | $ | $ 38,472 | $ 38,472 |
| Increase in Other Regulatory Liabilities Related to SFAS 158 | $ | $ (3,247) | $ (3,247) |
| Reduction in Accumulated Other Comprehensive Income | $ | $ 484 | $ 484 |
| Reduction in Deferred Income Taxes (under Deferred Credits) | $ | $ 294 | $ 294 |
| Increase in Other Post-Retirement Liabilities | $ (22,238) | $ (48,317) | $ (70,555) |
| **Non-Qualified Benefit Plan** | | | |
| Increase in Other Regulatory Assets Related to SFAS 158 | $ | $ 5,704 | $ 5,704 |
| Reduction in Accumulated Other Comprehensive Income | $ | $ 4,990 | $ 4,990 |
| Reduction in Deferred Income Taxes (under Deferred Credits) | $ | $ 3,027 | $ 3,027 |
| Increase in Other Deferred Credits | $ (30,115) | $ (13,721) | $ (43,836) |
| **Total Consolidated** | | | |
| Reduction in Prepaid Pension and Other Post-Retirement Benefit Costs | $ 77,679 | $ (16,673) | $ 61,006 |
| Increase in Other Regulatory Assets Related to SFAS 158 | $ | $ 61,907 | $ 61,907 |
| Increase in Other Regulatory Liabilities Related to SFAS 158 | $ | $ (3,247) | $ (3,247) |
| Reduction in Accumulated Other Comprehensive Income | $ | $ 12,482 | $ 12,482 |
| Reduction in Deferred Income Taxes (under Deferred Credits) | $ | $ 7,569 | $ 7,569 |
| Increase in Other Post-Retirement Liabilities | $ (22,238) | $ (48,317) | $ (70,555) |
| Increase in Other Deferred Credits | $ (30,115) | $ (13,721) | $ (43,836) |

(1) Amounts represent balances before applying the effects of the adoption of SFAS 158, but after giving effect to any necessary adjustments as a result of recognizing an additional minimum pension liability. At September 30, 2007, there was no additional minimum pension liability adjustment since the fair value of the plan assets exceeded the accumulated benefit obligation.

In order to adjust the funded status of its pension and other post-retirement benefit plans at September 30, 2008, the Company recorded a $57.2 million increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $7.3 million (net of deferred tax benefits of $4.4 million) increase to Accumulated Other Comprehensive Loss.

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The amounts recognized in accumulated other comprehensive loss, regulatory assets, and regulatory liabilities in fiscal 2008, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2009 are presented in the table below:

| | Retirement Plan | Other Post-Retirement Benefits (Thousands) | Non-Qualified Benefit Plan |
|---|---|---|---|
| **Amounts Recognized In Accumulated Other Comprehensive Loss, Regulatory Assets and Regulatory Liabilities(1)** | | | |
| Net Actuarial Gain/(Loss) | $ (71,637) | $ (53,108) | $ (13,530) |
| Transition Obligation | | (11,326) | |
| Prior Service (Cost) Credit | (5,495) | 7,561 | (11) |
| Net Amount Recognized | $ (77,132) | $ (56,873) | $ (13,541) |
| **Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)** | | | |
| Net Actuarial Gain/(Loss) | $ (5,676) | $ (9,271) | $ (1,322) |
| Transition Obligation | | (2,265) | |
| Prior Service (Cost) Credit | (731) | 1,074 | |
| Net Amount Expected to be Recognized | $ (6,407) | $ (10,462) | $ (1,322) |

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

In accordance with the provisions of SFAS 87, the Company recorded an additional minimum pension liability at September 30, 2005 representing the excess of the accumulated benefit obligation over the fair value of plan assets plus accrued amounts previously recorded. An intangible asset offset the additional liability to the extent of previously Unrecognized Prior Service Cost. The amount in excess of Unrecognized Prior Service Cost was recorded net of the related tax benefit as accumulated other comprehensive loss. At September 30, 2006, the Company reversed the additional minimum pension liability, intangible asset and accumulated other comprehensive loss recorded in prior years since the fair value of the plan assets exceeded the accumulated benefit obligation at September 30, 2006. The pre-tax amounts of the change in accumulated other comprehensive (income) loss related to the additional minimum pension liability adjustment at September 30, 2006 are shown in the table above. At September 30, 2007, prior to recognizing the impact of adopting SFAS 158, there was no additional minimum pension liability adjustment recorded since the fair value of the plan assets exceeded the accumulated benefit obligation. The projected benefit obligation, accumulated benefit obligation and fair value of assets for the Retirement Plan were as follows:

| | 2008 | 2007 (Thousands) | 2006 |
|---|---|---|---|
| Projected Benefit Obligation | $ 719,059 | $ 742,519 | $ 732,207 |
| Accumulated Benefit Obligation | $ 659,004 | $ 672,340 | $ 660,026 |
| Fair Value of Plan Assets | $ 695,089 | $ 765,144 | $ 664,520 |

The effect of the discount rate change for the Retirement Plan in 2008 was to decrease the projected benefit obligation of the Retirement Plan by $38.6 million. In 2008, other actuarial experience increased the projected benefit obligation for the Retirement Plan by $4.4 million. There was no change to the discount rate used to estimate the projected benefit obligation for the Retirement Plan during 2007. The effect of the discount rate change for the Retirement Plan in 2006 was to decrease the projected benefit obligation of the Retirement Plan by $113.1 million.

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The Company made cash contributions totaling $16.0 million to the Retirement Plan during the year ended September 30, 2008. The Company expects that the annual contribution to the Retirement Plan in 2009 will be in the range of $15.0 million to $20.0 million. As a result of the recent downturn in the stock markets and general economic conditions, it is likely that the Company will have to fund larger amounts to the Retirement Plan subsequent to 2009 in order to be in compliance with the Pension Protection Act of 2006. The following benefit payments, which reflect expected future service, are expected to be paid during the next five years and the five years thereafter: $50.5 million in 2009; $51.0 million in 2010; $51.4 million in 2011; $51.9 million in 2012; $52.9 million in 2013; and $286.7 million in the five years thereafter.

In addition to the Retirement Plan discussed above, the Company also has a Non Qualified benefit plan that covers a group of management employees designated by the Chief Executive Officer of the Company. This plan provides for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit cost associated with this plan was $5.0 million, $5.5 million and $5.4 million in 2008, 2007 and 2006, respectively. At September 30, 2008, an $8.0 million (pre-tax) loss was included in accumulated other comprehensive income (loss) on the Consolidated Balance Sheet. This was first recognized in 2007 upon adoption of SFAS 158. There were no amounts recognized in other comprehensive income (loss) attributable to the recognition of an additional minimum liability for 2006. The accumulated benefit obligation for this plan was $31.8 million and $28.8 million at September 30, 2008 and 2007, respectively. The projected benefit obligation for the plan was $47.5 million and $43.8 million at September 30, 2008 and 2007, respectively. The actuarial valuations for this plan were determined based on a discount rate of 6.75%, 6.25% and 6.25% as of September 30, 2008, 2007 and 2006, respectively; a rate of compensation increase of 10.0% as of September 30, 2008, 2007 and 2006; and an expected long-term rate of return on plan assets of 8.25% at September 30, 2008, 2007 and 2006.

The effect of the discount rate change in 2008 was to decrease the other post-retirement benefit obligation by $26.3 million. Effective July 1, 2008, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $20.0 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2008 by $8.1 million.

There was no change to the discount rate used to estimate the other post-retirement benefit obligation during 2007. Effective July 1, 2007, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $8.6 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2007 by $23.0 million.

The effect of the discount rate change in 2006 was to decrease the other post-retirement benefit obligation by $77.5 million. Effective July 1, 2006, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to decrease the other post-retirement benefit obligation by $1.7 million. A change in the disability assumption decreased the other post-retirement benefit obligation by $1.4 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2006 by $34.4 million.

On December 8, 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. This Act introduced a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In accordance with FASB Staff Position FAS 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 , since the Company is assumed to continue to provide a prescription drug benefit to retirees in the point of service and indemnity plans that is at least actuarially equivalent to Medicare Part D, the impact of the Act was reflected as of December 8, 2003.

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

The estimated gross benefit payments and gross amount of subsidy receipts are as follows:

| | Benefit Payments | Subsidy Receipts |
|---|---|---|
| 2009 | $ 26,210,000 | $ (1,714,000) |
| 2010 | $ 28,248,000 | $ (1,942,000) |
| 2011 | $ 30,122,000 | $ (2,167,000) |
| 2012 | $ 31,484,000 | $ (2,437,000) |
| 2013 | $ 32,687,000 | $ (2,719,000) |
| 2014 through 2018 | $ 181,354,000 | $ (17,304,000) |

| | 2008 | 2007 | 2006 |
|---|---|---|---|
| Rate of Increase for Pre Age 65 Participants | 9.0%(1) | 8.0%(2) | 9.0%(2) |
| Rate of Increase for Post Age 65 Participants | 7.0%(1) | 6.67%(2) | 7.0%(2) |
| Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits | 10.0%(1) | 10.0%(2) | 11.0%(2) |
| Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement | 7.0%(1) | 7.0%(3) | 5.25%(4) |

(1) It was assumed that this rate would gradually decline to 5.0% by 2018.

(2) It was assumed that this rate would gradually decline to 5.0% by 2014.

(3) It was assumed that this rate would gradually decline to 5.0% by 2016.

(4) It was assumed that this rate would gradually decline to 5.0% by 2017.

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2008 would increase by $45.1 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2008 by $4.7 million. If the health care cost trend rates were decreased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2008 would decrease by $38.4 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2007 by $3.9 million.

The Company made cash contributions totaling $29.1 million to the VEBA trusts and 401(h) accounts during the year ended September 30, 2008. In addition, the Company made direct payments of $0.1 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2008. The Company expects that the annual contribution to the VEBA trusts and 401(h) accounts in 2009 will be in the range of $25.0 million to

$30.0 million.

The Company s Retirement Plan weighted average asset allocations (excluding the 401(h) accounts) at September 30, 2008, 2007 and 2006 by asset category are as follows:

| | Target Allocation | Percentage of Plan Assets at September 30 | | |
|---|---|---|---|---|
| **Asset Category** | **2009** | **2008** | **2007** | **2006** |
| Equity Securities | 60-75% | 67% | 70% | 67% |
| Fixed Income Securities | 20-35% | 29% | 24% | 26% |
| Other | 0-15% | 4% | 6% | 7% |
| Total | | 100% | 100% | 100% |

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company s weighted average asset allocations for its VEBA trusts and 401(h) accounts at September 30, 2008, 2007 and 2006 by asset category are as follows:

| Asset Category | Target Allocation 2009 | Percentage of Plan Assets at September 30 2008 | 2007 | 2006 |
|---|---|---|---|---|
| Equity Securities | 85-100% | 93% | 95% | 95% |
| Fixed Income Securities | 0-15% | 2% | 1% | 1% |
| Other | 0-15% | 5% | 4% | 4% |
| Total | | 100% | 100% | 100% |

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

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

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

The discount rate which is used to present value the future benefit payment obligations of the Retirement Plan, the Non-Qualified benefit plan, and the Company s other post-retirement benefits is 6.75% as of September 30, 2008. The Company utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year s anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments.

## Note H Commitments and Contingencies

### *Environmental Matters*

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

It is the Company s policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2008, 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 $19.4 million to $23.6 million. The minimum estimated liability of $19.4 million has been recorded on the Consolidated Balance Sheet at September 30, 2008. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet (refer to Note C Regulatory Matters for further discussion of the insurance proceeds). Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

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## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

*(i) Former Manufactured Gas Plant Sites*

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

With respect to another former manufactured gas plant site, the Company received, in 1998 and again in October 1999, notice that the NYDEC believes the Company is responsible for contamination discovered at the site located in New York for which the Company had not been named as a PRP. In February 2007, the NYDEC identified the Company as a PRP for the site and issued a proposed remedial action plan. The NYDEC estimated clean-up costs under its proposed remedy to be $8.9 million if implemented. Although the Company commented to the NYDEC that the proposed remedial action plan contained a number of material errors, omissions and procedural defects, the NYDEC, in a March 2007 Record of Decision, selected the remedy it had previously proposed. In July 2007, the Company appealed the NYDEC s Record of Decision to the New York State Supreme Court, Albany County. The Court dismissed the appeal in January 2008. The Company filed a notice of appeal in February 2008. In July 2008, the Company withdrew its appeal and, without admitting liability or fault, agreed to the terms of an Order on Consent issued by the NYDEC. Pursuant to the order, the Company will remediate the site consistent with the remedy selected in the NYDEC s Record of Decision. The Company reimbursed the NYDEC in the amount of approximately $1.5 million for costs incurred in connection with the site from 1998 through May 30, 2007. The Company acknowledged that additional charges related to the site will be billed to the Company at a later date, including costs incurred by the NYDEC after May 30, 2007 and any costs incurred by the New York Department of Health. The Company has not received and does not expect to receive any estimates of such additional costs. The Company has submitted a Remedial Design/Remedial Action work plan to the NYDEC in accordance with the Order on Consent and has increased its recorded estimated minimum liability for this site to $16.5 million.

*(ii) Other*

In June 2007, the NYDEC notified the Company, as well as a number of other companies, of their potential liability with respect to a remedial action at a waste disposal site in New York. The notification identified the Company as one of approximately 500 other companies considered to be PRPs related to this site and requested that the remedy the NYDEC proposed in a Record of Decision issued in March 2006 be performed. The estimated clean-up costs under the remedy selected by the NYDEC are estimated to be approximately $13.0 million if implemented. The Company participates in an organized group with other PRPs who are addressing this site.

***Other***

The Company, in its Utility segment, Energy Marketing segment, and All Other category, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. Substantially all of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $793.2 million in 2009, $168.0 million in 2010, $55.6 million in 2011, $47.0 million in 2012, $21.6 million in 2013, and $100.7 million thereafter. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment s service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of buildings, vehicles, construction tools, meters, computer equipment and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $6.0 million in 2009, $4.6 million in 2010, $3.6 million in 2011, $3.2 million in 2012, $2.5 million in 2013, and $12.4 million thereafter.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company has entered into several contractual commitments associated with the construction of the Empire Connector project, including the pipeline construction itself and construction of a compressor station, as well as other contractual commitments for engineering and consulting services. The Empire Connector is scheduled to go in service by December 2008. As of September 30, 2008, the future contractual commitments related to the construction of the Empire Connector during 2009 is $13.5 million.

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

**Note I Discontinued Operations**

On August 31, 2007, the Company, in its Exploration and Production segment, completed the sale of SECI, Seneca s wholly owned subsidiary that operated in Canada. The Company received approximately $232.1 million of proceeds from the sale, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. In December 2007, the Canadian government issued the tax clearance certificate, thereby releasing the proceeds from restriction as of December 31, 2007. The sale resulted in the recognition of a gain of approximately $120.3 million, net of tax, during the fourth quarter of 2007. SECI is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in the provinces of Alberta, Saskatchewan and British Columbia in Canada. The decision to sell was based on lower than expected returns from the Canadian oil and gas properties combined with difficulty in finding significant new reserves. Seneca will continue its exploration and development activities in Appalachia, the Gulf of Mexico, and California. As a result of the decision to sell SECI, the Company began presenting all SECI operations as discontinued operations during the fourth quarter of 2007.

The following is selected financial information of the discontinued operations for SECI:

| | Year Ended September 30 | |
|---|---|---|
| | 2007 | 2006 |
| | (Thousands) | |
| Operating Revenues | $ 50,495 | $ 71,984 |
| Operating Expenses | 33,306 | 151,532 |
| Operating Income (Loss) | 17,189 | (79,548) |
| Interest Income | 1,082 | 866 |
| Income (Loss) before Income Taxes | 18,271 | (78,682) |

| | | |
|---|---|---|
| Income Tax Expense (Benefit) | 2,792 | (32,159) |
| Income (Loss) from Discontinued Operations | 15,479 | (46,523) |
| Gain on Disposal, Net of Taxes of $39,572 | 120,301 | |
| Income (Loss) from Discontinued Operations | $ 135,780 | $ (46,523) |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

## Note J Business Segment Information

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

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

The Pipeline and Storage segment operations are regulated. The FERC regulates the operations of Supply Corporation and the NYPSC regulates the operations of Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers (including NFR) and pipeline companies in the northeastern United States markets. Empire transports natural gas from the United States/Canadian border near Buffalo, New York into Central New York just north of Syracuse, New York. Empire is constructing the Empire Connector project, which consists of a compressor station and a pipeline extension from near Rochester, New York to an interconnection near Corning, New York with the unaffiliated Millennium Pipeline. The Empire Connector is anticipated to be ready to commence service in early December 2008, on or before the in-service date of the Millennium Pipeline. Empire transports gas to major industrial companies, utilities (including Distribution Corporation) and power producers.

The Exploration and Production segment, through Seneca, is engaged in exploration for, and development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in the Gulf Coast region of Texas, Louisiana and Alabama. Seneca s production is, for the most part, sold to purchasers located in the vicinity of its wells. As disclosed in Note I Discontinued Operations, on August 31, 2007, Seneca completed the sale of SECI, its wholly owned subsidiary operating in Canada, for a gain of approximately $120.3 million, net of tax, during the fourth quarter of 2007. As a result of the sale, SECI s operations have been reported as discontinued operations.

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

The Timber segment s operations are carried out by the Northeast division of Seneca and by Highland. This segment has timber holdings (primarily high quality hardwoods) in the northeastern United States and sawmills and kilns in Pennsylvania.

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

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

| | Year Ended September 30, 2008 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber (Thousands) | Total Reported Segments | All Other | Corporate and Intersegment Eliminations | T Cons |
| from External s | $ 1,194,657 | $ 135,052 | $ 466,760 | $ 549,932 | $ 49,516 | $ 2,395,917 | $ 3,749 | $ 695 | $ 2, |
| ent Revenues | $ 15,612 | $ 81,504 | $ | $ 1,300 | $ | $ 98,416 | $ 14,115 | $ (112,531) | $ |
| come | $ 1,836 | $ 843 | $ 10,921 | $ 323 | $ 1,053 | $ 14,976 | $ 179 | $ (4,340) | $ |
| xpense | $ 27,683 | $ 13,783 | $ 41,645 | $ 175 | $ 3,142 | $ 86,428 | $ 640 | $ (13,099) | $ |
| ion, Depletion rtization | $ 39,113 | $ 32,871 | $ 92,221 | $ 42 | $ 4,904 | $ 169,151 | $ 783 | $ 689 | $ |
| ax Expense | $ 36,303 | $ 34,008 | $ 92,686 | $ 3,180 | $ (378) | $ 165,799 | $ 2,564 | $ (441) | $ |
| om idated es | $ | $ | $ | $ | $ | $ | $ 6,303 | $ | $ |
| Profit: Net Loss) | $ 61,472 | $ 54,148 | $ 146,612 | $ 5,889 | $ 107 | $ 268,228 | $ 5,672 | $ (5,172) | $ |
| ures for to ed Assets | $ 57,457 | $ 165,520 | $ 192,187 | $ 39 | $ 1,354 | $ 416,557 | $ 131 | $ (2,186) | $ |

| | At September 30, 2008 (Thousands) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| nt Assets | $ 1,643,665 | $ 948,984 | $ 1,416,120 | $ 89,527 | $ 149,896 | $ 4,248,192 | $ 67,978 | $ (185,983) | $ 4,13 |

| | Year Ended September 30, 2007 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber (Thousands) | Total Reported Segments | All Other | Corporate and Intersegment Eliminations | T Cons |
| from External rs | $ 1,106,453 | $ 130,410 | $ 324,037 | $ 413,612 | $ 58,897 | $ 2,033,409 | $ 5,385 | $ 772 | $ 2, |
| nent Revenues | $ 14,271 | $ 81,556 | $ | $ | $ | $ 95,827 | $ 8,726 | $ (104,553) | $ |
| ncome | $ (2,345) | $ 357 | $ 9,905 | $ 682 | $ 1,249 | $ 9,848 | $ 16 | $ (8,314) | $ |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| xpense | $ 28,190 | $ 9,623 | $ 51,743 | $ 263 | $ 3,265 | $ 93,084 | $ 2,687 | $ (21,296) | $ |
| tion, Depletion rtization | $ 40,541 | $ 32,985 | $ 78,174 | $ 33 | $ 4,709 | $ 156,442 | $ 785 | $ 692 | $ |
| ax Expense | $ 31,642 | $ 35,740 | $ 52,421 | $ 5,654 | $ 2,818 | $ 128,275 | $ 1,647 | $ 1,891 | $ |
| rom lidated ries | $ | $ | $ | $ | $ | $ | $ 4,979 | $ | $ |
| Profit: Income tinuing ns | $ 50,886 | $ 56,386 | $ 74,889 | $ 7,663 | $ 3,728 | $ 193,552 | $ 2,564 | $ 5,559 | $ 2 |
| ures for s to ed Assets tinuing ns | $ 54,185 | $ 43,226 | $ 146,687 | $ 76 | $ 3,657 | $ 247,831 | $ 87 | $ (319) | $ 2 |

**At September 30, 2007**
**(Thousands)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| nt Assets | $ 1,565,593 | $ 810,957 | $ 1,326,073 | $ 59,802 | $ 165,224 | $ 3,927,649 | $ 66,531 | $ (105,768) | $ 3,88 |

**Year Ended September 30, 2006**

| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber (Thousands) | Total Reported Segments | All Other | Corporate and Intersegment Eliminations | T Cons |
|---|---|---|---|---|---|---|---|---|---|
| from External rs | $ 1,265,695 | $ 132,921 | $ 274,896 | $ 497,069 | $ 65,024 | $ 2,235,605 | $ 3,304 | $ 766 | $ 2,2 |
| ent Revenues | $ 15,068 | $ 81,431 | $ | $ | $ 5 | $ 96,504 | $ 9,444 | $ (105,948) | $ |
| ncome | $ 4,889 | $ 454 | $ 7,816 | $ 445 | $ 747 | $ 14,351 | $ 22 | $ (4,964) | $ |
| xpense | $ 26,174 | $ 6,620 | $ 50,457 | $ 227 | $ 3,095 | $ 86,573 | $ 2,555 | $ (10,547) | $ |
| tion, Depletion rtization | $ 40,172 | $ 36,876 | $ 67,122 | $ 53 | $ 6,495 | $ 150,718 | $ 789 | $ 492 | $ 1 |
| ax Expense | $ 35,699 | $ 33,896 | $ 29,351 | $ 3,748 | $ 3,277 | $ 105,971 | $ 969 | $ 1,305 | $ 1 |
| rom lidated ries | $ | $ | $ | $ | $ | $ | $ 3,583 | $ | $ |
| Profit: Income om Continuing ns | $ 49,815 | $ 55,633 | $ 67,494 | $ 5,798 | $ 5,704 | $ 184,444 | $ 359 | $ (189) | $ 1 |
| ures for s to ed Assets tinuing ns | $ 54,414 | $ 26,023 | $ 166,535 | $ 16 | $ 2,323 | $ 249,311 | $ 85 | $ 2,995 | $ 2 |

**At September 30, 2006**
**(Thousands)**

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| nt Assets | $ 1,498,442 | $ 767,889 | $ 1,209,969(1) | $ 81,374 | $ 159,421 | $ 3,717,095 | $ 64,287 | $ (17,634) | $ 3,76 |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

(1) Amount includes $134,930 of assets of SECI, which has been classified as discontinued operations as of September 30, 2007. (See Note I Discontinued Operations).

| Geographic Information | For The Year Ended September 30 2008 | 2007 (Thousands) | 2006 |
|---|---|---|---|
| **Revenues from External Customers(1):** | | | |
| United States | $ 2,400,361 | $ 2,039,566 | $ 2,239,675 |

| | At September 30 2008 | 2007 (Thousands) | 2006 |
|---|---|---|---|
| **Long-Lived Assets:** | | | |
| United States | $ 3,630,709 | $ 3,334,274 | $ 3,181,769 |
| Assets of Discontinued Operations | | | 97,234 |
| | $ 3,630,709 | $ 3,334,274 | $ 3,279,003 |

(1) Revenue is based upon the country in which the sale originates. This table excludes revenues from Canadian discontinued operations of $50,495 and $71,984 for September 30, 2007 and 2006, respectively.

**Note K Investments in Unconsolidated Subsidiaries**

The Company s unconsolidated subsidiaries consist of equity method investments in Seneca Energy, Model City and ESNE. The Company has 50% interests in each of these entities. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. ESNE generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. ESNE sells its electricity into the New York power grid.

A summary of the Company s investments in unconsolidated subsidiaries at September 30, 2008 and 2007 is as follows:

| | At September 30 2008 | 2007 (Thousands) |
|---|---|---|

| | | |
|---|---|---|
| ESNE | $ 3,958 | $ 4,652 |
| Seneca Energy | 10,589 | 12,033 |
| Model City | 1,732 | 1,571 |
| | $ 16,279 | $ 18,256 |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

### Note L Intangible Assets

As a result of the Empire and Toro acquisitions, the Company acquired certain intangible assets during 2003. In the case of the Empire acquisition, the intangible assets represent the fair value of various long-term transportation contracts with Empire s customers. In the case of the Toro acquisition, the intangible assets represent the fair value of various long-term gas purchase contracts with the various landfills. These intangible assets are being amortized over the lives of the transportation and gas purchase contracts with no residual value at the end of the amortization period. The weighted-average amortization period for the gross carrying amount of the transportation contracts is 8 years. The weighted-average amortization period for the gross carrying amount of the gas purchase contracts is 20 years. Details of these intangible assets are as follows (in thousands):

| | At September 30, 2008 | | | At September 30, 2007 |
|---|---|---|---|---|
| | Gross Carrying Amount | Accumulated Amortization | Net Carrying Amount | Net Carrying Amount |
| Intangible Assets Subject to Amortization: | | | | |
| Long-Term Transportation Contracts | $ 8,580 | $ (6,058) | $ 2,522 | $ 3,591 |
| Long-Term Gas Purchase Contracts | 31,864 | (8,212) | 23,652 | 25,245 |
| | $ 40,444 | $ (14,270) | $ 26,174 | $ 28,836 |
| Aggregate Amortization Expense: | | | | |
| For the Year Ended September 30, 2008 | $ 2,662 | | | |
| For the Year Ended September 30, 2007 | $ 2,662 | | | |
| For the Year Ended September 30, 2006 | $ 2,662 | | | |

The gross carrying amount of intangible assets subject to amortization at September 30, 2008 remained unchanged from September 30, 2007. The only activity with regard to intangible assets subject to amortization was amortization expense as shown on the table above. Amortization expense for the long-term transportation contracts is estimated to be $0.5 million in 2009, and $0.4 million in 2010, 2011, 2012 and 2013. Amortization expense for the long-term gas purchase contracts is estimated to be $1.6 million annually for 2009, 2010, 2011, 2012 and 2013.

### Note M Quarterly Financial Data (unaudited)

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

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## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

| Quarter Ended | Operating Revenues | Operating Income | Income from Continuing Operations | Income from Discontinued Operations | Net Income Available for Common Stock | Earnings from Continuing Operations per Common Share Basic | Earnings from Continuing Operations per Common Share Diluted | Earnings per Common Share Basic | Earnings per Common Share Diluted |
|---|---|---|---|---|---|---|---|---|---|
| | (Thousands, except per common share amounts) | | | | | | | | |
| **2008** | | | | | | | | | |
| 9/30/2008 | $ 397,858 | $ 79,149 | $ 43,266 | $ | $ 43,266 | $ 0.54 | $ 0.52 | $ 0.54 | $ 0.52 |
| 6/30/2008 | $ 548,382 | $ 110,947 | $ 59,855 | $ | $ 59,855 | $ 0.74 | $ 0.72 | $ 0.74 | $ 0.72 |
| 3/31/2008 | $ 885,853 | $ 170,020 | $ 95,003(1) | $ | $ 95,003(1) | $ 1.14 | $ 1.11 | $ 1.14 | $ 1.11 |
| 12/31/2007 | $ 568,268 | $ 126,009 | $ 70,604 | $ | $ 70,604 | $ 0.84 | $ 0.82 | $ 0.84 | $ 0.82 |
| **2007** | | | | | | | | | |
| 9/30/2007 | $ 302,030 | $ 73,504 | $ 34,295 | $ 123,395(2) | $ 157,690(2) | $ 0.41 | $ 0.40 | $ 1.89 | $ 1.84 |
| 6/30/2007 | $ 448,779 | $ 83,933 | $ 41,212(3) | $ 5,586 | $ 46,798(3) | $ 0.49 | $ 0.48 | $ 0.56 | $ 0.55 |
| 3/31/2007 | $ 798,100 | $ 142,404 | $ 75,480(4) | $ 2,967 | $ 78,447(4) | $ 0.91 | $ 0.89 | $ 0.95 | $ 0.92 |
| 12/31/2006 | $ 490,657 | $ 96,657 | $ 50,688(5) | $ 3,832 | $ 54,520(5) | $ 0.61 | $ 0.60 | $ 0.66 | $ 0.64 |

(1) Includes a $0.6 million gain on sale of turbine.

(2) Includes a $120.3 million gain on the sale of SECI.

(3) Includes $4.8 million of income associated with the reversal of reserve for preliminary project costs associated with the Empire Connector project.

(4) Includes $2.3 million of income associated with the reversal of a purchased gas expense accrual related to the resolution of a contingency.

(5) Includes a $1.9 million positive earnings impact associated with the discontinuance of hedge accounting on an interest rate collar.

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

At September 30, 2008, there were 16,544 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange. Information related to restrictions on the payment of dividends can be found in Note E Capitalization and Short-Term Borrowings. The quarterly price ranges (based on intra-day prices) and quarterly dividends declared for the fiscal years ended September 30, 2008 and 2007, are shown below:

| Quarter Ended | Price Range High | Price Range Low | Dividends Declared |
|---|---|---|---|
| **2008** | | | |
| 9/30/2008 | $ 60.36 | $ 39.16 | $ .325 |
| 6/30/2008 | $ 63.71 | $ 47.00 | $ .325 |
| 3/31/2008 | $ 48.78 | $ 38.04 | $ .31 |
| 12/31/2007 | $ 50.29 | $ 45.20 | $ .31 |
| **2007** | | | |
| 9/30/2007 | $ 47.00 | $ 40.95 | $ .31 |
| 6/30/2007 | $ 47.87 | $ 42.75 | $ .31 |
| 3/31/2007 | $ 43.79 | $ 36.94 | $ .30 |
| 12/31/2006 | $ 40.21 | $ 35.02 | $ .30 |

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following supplementary information is presented in accordance with SFAS 69, Disclosures about Oil and Gas Producing Activities, and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars.

***Capitalized Costs Relating to Oil and Gas Producing Activities***

| | At September 30 2008 | 2007 |
|---|---|---|
| | (Thousands) | |
| Proved Properties(1) | $ 1,783,276 | $ 1,583,956 |
| Unproved Properties | 23,285 | 20,005 |
| | 1,806,561 | 1,603,961 |
| Less Accumulated Depreciation, Depletion and Amortization | 718,166 | 627,073 |
| | $ 1,088,395 | $ 976,888 |

(1) Includes asset retirement costs of $60.9 million and $40.9 million at September 30, 2008 and 2007, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Following is a summary of costs excluded from amortization at September 30, 2008:

| | Total as of September 30, 2008 | Year Costs Incurred 2008 | 2007 | 2006 | Prior |
|---|---|---|---|---|---|
| | | (Thousands) | | | |
| Acquisition Costs | $ 23,285 | $ 7,914 | $ 2,433 | $ 11,918 | $ 1,020 |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| **United States** | | | |
| Property Acquisition Costs: | | | |
| Proved | $ 16,474 | $ 2,621 | $ 5,339 |
| Unproved | 8,449 | 3,210 | 8,844 |
| Exploration Costs | 56,274 | 26,891 | 64,087 |
| Development Costs | 106,975 | 113,206 | 87,738 |
| Asset Retirement Costs | 20,048 | 2,139 | 10,965 |
| | 208,220 | 148,067 | 176,973 |
| **Canada Discontinued Operations** | | | |
| Property Acquisition Costs: | | | |
| Proved | | (1,404) | (427) |
| Unproved | | (1,142) | 6,492 |
| Exploration Costs | | 20,134 | 20,778 |
| Development Costs | | 11,414 | 14,385 |
| Asset Retirement Costs | | 167 | 279 |
| | | 29,169 | 41,507 |
| **Total** | | | |
| Property Acquisition Costs: | | | |
| Proved | 16,474 | 1,217 | 4,912 |
| Unproved | 8,449 | 2,068 | 15,336 |
| Exploration Costs | 56,274 | 47,025 | 84,865 |
| Development Costs | 106,975 | 124,620 | 102,123 |
| Asset Retirement Costs | 20,048 | 2,306 | 11,244 |
| | $ 208,220 | $ 177,236 | $ 218,480 |

For the years ended September 30, 2008, 2007 and 2006, the Company spent $25.4 million, $30.3 million and $55.6 million, respectively, developing proved undeveloped reserves.

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## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***Results of Operations for Producing Activities***

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | (Thousands, except per Mcfe amounts) | | |
| **United States** | | | |
| Operating Revenues: | | | |
| Natural Gas (includes revenues from sales to affiliates of $443, $325 and $106, respectively) | $ 216,623 | $ 135,399 | $ 152,451 |
| Oil, Condensate and Other Liquids | 305,887 | 189,539 | 195,050 |
| Total Operating Revenues(1) | 522,510 | 324,938 | 347,501 |
| Production/Lifting Costs | 66,685 | 48,410 | 41,354 |
| Accretion Expense | 4,056 | 3,704 | 2,412 |
| Depreciation, Depletion and Amortization ($2.23, $1.97 and $1.74 per Mcfe of production) | 91,093 | 77,452 | 66,488 |
| Income Tax Expense | 144,922 | 78,928 | 88,104 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | 215,754 | 116,444 | 149,143 |
| **Canada Discontinued Operations** | | | |
| Operating Revenues: | | | |
| Natural Gas | | 39,114 | 54,819 |
| Oil, Condensate and Other Liquids | | 10,313 | 13,985 |
| Total Operating Revenues(1) | | 49,427 | 68,804 |
| Production/Lifting Costs | | 14,846 | 14,628 |
| Accretion Expense | | 249 | 258 |
| Depreciation, Depletion and Amortization ($0, $1.67 and $2.95 per Mcfe of production) | | 12,787 | 27,439 |
| Impairment of Oil and Gas Producing Properties(2) | | | 104,739 |
| Income Tax Expense (Benefit) | | 3,703 | (31,987) |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | | 17,842 | (46,273) |

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**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

| | Year Ended September 30 | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| | (Thousands, except per Mcfe amounts) | | |
| **Total** | | | |
| Operating Revenues: | | | |
| Natural Gas (includes revenues from sales to affiliates of $443, $325 and $106, respectively) | 216,623 | 174,513 | 207,270 |
| Oil, Condensate and Other Liquids | 305,887 | 199,852 | 209,035 |
| Total Operating Revenues(1) | 522,510 | 374,365 | 416,305 |
| Production/Lifting Costs | 66,685 | 63,256 | 55,982 |
| Accretion Expense | 4,056 | 3,953 | 2,670 |
| Depreciation, Depletion and Amortization ($2.23, $1.92 and $1.98 per Mcfe of production) | 91,093 | 90,239 | 93,927 |
| Impairment of Oil and Gas Producing Properties(2) | | | 104,739 |
| Income Tax Expense | 144,922 | 82,631 | 56,117 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | $ 215,754 | $ 134,286 | $ 102,870 |

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

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

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## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

*Reserve Quantity Information*

The Company s proved oil and gas reserves are located in the United States. The estimated quantities of proved reserves disclosed in the table below are based upon estimates by qualified Company geologists and engineers and are audited by independent petroleum engineers. Such estimates 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.

| | Gas MMcf | | | | | |
|---|---|---|---|---|---|---|
| | U. S. | | | | | |
| | Gulf Coast Region | West Coast Region | Appalachian Region | Total U.S. | Canada (Discontinued Operations) | Total Company |
| Proved Developed and Undeveloped Reserves: | | | | | | |
| September 30, 2005 | 38,470 | 70,459 | 83,125 | 192,054 | 46,086 | 238,140 |
| Extensions and Discoveries | 11,763 | 1,815 | 11,132 | 24,710 | 6,229 | 30,939 |
| Revisions of Previous Estimates | 679 | 5,757 | (7,776) | (1,340) | (11,096) | (12,436) |
| Production | (9,110) | (3,880) | (5,108) | (18,098) | (7,673) | (25,771) |
| Purchases of Minerals in Place | | 1,715 | | 1,715 | | 1,715 |
| Sales of Minerals in Place | | | | | (12) | (12) |
| September 30, 2006 | 41,802 | 75,866 | 81,373 | 199,041 | 33,534 | 232,575 |
| Extensions and Discoveries | 3,577 | | 29,676 | 33,253 | 1,333 | 34,586 |
| Revisions of Previous Estimates | (9,851) | 1,238 | 1,618 | (6,995) | 11,634 | 4,639 |
| Production | (10,356) | (3,929) | (5,555) | (19,840) | (6,426) | (26,266) |
| Sales of Minerals in Place | (36) | | (34) | (70) | (40,075) | (40,145) |
| September 30, 2007 | 25,136 | 73,175 | 107,078 | 205,389 | | 205,389 |
| Extensions and Discoveries | 8,759 | | 31,322 | 40,081 | | 40,081 |
| Revisions of Previous Estimates | 2,156 | 566 | (3,460) | (738) | | (738) |
| Production | (11,033) | (4,039) | (7,269) | (22,341) | | (22,341) |
| Purchases of Minerals in Place | | 4,539 | 727 | 5,266 | | 5,266 |
| Sales of Minerals in Place | (377) | (1,381) | | (1,758) | | (1,758) |
| September 30, 2008 | 24,641 | 72,860 | 128,398 | 225,899 | | 225,899 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Proved Developed Reserves: | | | | | | |
| September 30, 2005 | 23,108 | 58,692 | 83,125 | 164,925 | 43,980 | 208,905 |
| September 30, 2006 | 32,345 | 64,196 | 81,373 | 177,914 | 33,534 | 211,448 |
| September 30, 2007 | 25,136 | 66,017 | 96,674 | 187,827 | | 187,827 |
| September 30, 2008 | 18,242 | 68,453 | 115,824 | 202,519 | | 202,519 |

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

| | Oil Mbbl | | | | | |
|---|---|---|---|---|---|---|
| | U. S. | | | | | |
| | Gulf Coast Region | West Coast Region | Appalachian Region | Total U.S. | Canada (Discontinued Operations) | Total Company |
| Proved Developed and Undeveloped Reserves: | | | | | | |
| September 30, 2005 | 1,295 | 57,085 | 177 | 58,557 | 1,700 | 60,257 |
| Extensions and Discoveries | 39 | 172 | 108 | 319 | 128 | 447 |
| Revisions of Previous Estimates | 595 | (80) | 57 | 572 | 101 | 673 |
| Production | (685) | (2,582) | (69) | (3,336) | (272) | (3,608) |
| Purchases of Minerals in Place | | 274 | | 274 | | 274 |
| Sales of Minerals in Place | | | | | (25) | (25) |
| September 30, 2006 | 1,244 | 54,869 | 273 | 56,386 | 1,632 | 58,018 |
| Extensions and Discoveries | 63 | | 281 | 344 | 108 | 452 |
| Revisions of Previous Estimates | 851 | (6,822) | 84 | (5,887) | (76) | (5,963) |
| Production | (717) | (2,403) | (124) | (3,244) | (206) | (3,450) |
| Sales of Minerals in Place | (6) | | (7) | (13) | (1,458) | (1,471) |
| September 30, 2007 | 1,435 | 45,644 | 507 | 47,586 | | 47,586 |
| Extensions and Discoveries | 298 | 471 | 58 | 827 | | 827 |
| Revisions of Previous Estimates | 203 | (34) | (64) | 105 | | 105 |
| Production | (505) | (2,460) | (105) | (3,070) | | (3,070) |
| Purchases of Minerals in Place | | 2,084 | | 2,084 | | 2,084 |
| Sales of Minerals in Place | (73) | (1,261) | | (1,334) | | (1,334) |
| September 30, 2008 | 1,358 | 44,444 | 396 | 46,198 | | 46,198 |
| Proved Developed Reserves: | | | | | | |
| September 30, 2005 | 1,229 | 41,701 | 177 | 43,107 | 1,700 | 44,807 |
| September 30, 2006 | 1,217 | 42,522 | 273 | 44,012 | 1,632 | 45,644 |
| September 30, 2007 | 1,435 | 36,509 | 483 | 38,427 | | 38,427 |
| September 30, 2008 | 1,313 | 37,224 | 357 | 38,894 | | 38,894 |

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

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company s oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, it is based on year-end prices and costs adjusted only for existing contractual changes, and it assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

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

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| **United States** | | | |
| Future Cash Inflows | $ 5,845,214 | $ 4,879,496 | $ 3,911,059 |
| Less: | | | |
| Future Production Costs | 1,231,705 | 872,536 | 758,258 |
| Future Development Costs | 265,515 | 229,987 | 205,497 |
| Future Income Tax Expense at Applicable Statutory Rate | 1,645,351 | 1,423,707 | 1,019,307 |
| Future Net Cash Flows | 2,702,643 | 2,353,266 | 1,927,997 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | 1,434,799 | 1,292,804 | 1,066,338 |
| Standardized Measure of Discounted Future Net Cash Flows | 1,267,844 | 1,060,462 | 861,659 |
| **Canada Discontinued Operations** | | | |
| Future Cash Inflows | | | 197,227 |
| Less: | | | |
| Future Production Costs | | | 92,234 |
| Future Development Costs | | | 11,520 |
| Future Income Tax Expense at Applicable Statutory Rate | | | (151) |
| Future Net Cash Flows | | | 93,624 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | | | 19,375 |
| Standardized Measure of Discounted Future Net Cash Flows | | | 74,249 |
| **Total** | | | |
| Future Cash Inflows | 5,845,214 | 4,879,496 | 4,108,286 |
| Less: | | | |
| Future Production Costs | 1,231,705 | 872,536 | 850,492 |
| Future Development Costs | 265,515 | 229,987 | 217,017 |
| Future Income Tax Expense at Applicable Statutory Rate | 1,645,351 | 1,423,707 | 1,019,156 |
| Future Net Cash Flows | 2,702,643 | 2,353,266 | 2,021,621 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | 1,434,799 | 1,292,804 | 1,085,713 |
| Standardized Measure of Discounted Future Net Cash Flows | $ 1,267,844 | $ 1,060,462 | $ 935,908 |

**NATIONAL FUEL GAS COMPANY**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | **2008** | **2007** | **2006** |
| | | (Thousands) | |
| **United States** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | $ 1,060,462 | $ 861,659 | $ 1,491,532 |
| Sales, Net of Production Costs | (455,825) | (276,529) | (306,147) |
| Net Changes in Prices, Net of Production Costs | 509,705 | 539,895 | (941,545) |
| Purchases of Minerals in Place | 67,768 | | 7,607 |
| Sales of Minerals in Place | (31,642) | 484 | |
| Extensions and Discoveries | 143,394 | 98,751 | 66,975 |
| Changes in Estimated Future Development Costs | (100,684) | (83,199) | (83,750) |
| Previously Estimated Development Costs Incurred | 65,156 | 58,710 | 67,048 |
| Net Change in Income Taxes at Applicable Statutory Rate | (119,585) | (174,920) | 404,176 |
| Revisions of Previous Quantity Estimates | (3,936) | (140,203) | 4,850 |
| Accretion of Discount and Other | 133,031 | 175,814 | 150,913 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | 1,267,844 | 1,060,462 | 861,659 |
| **Canada Discontinued Operations** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | | 74,249 | 206,643 |
| Sales, Net of Production Costs | | (34,581) | (54,176) |
| Net Changes in Prices, Net of Production Costs | | 35,628 | (180,216) |
| Sales of Minerals in Place | | (151,236) | (238) |
| Extensions and Discoveries | | 6,908 | 10,369 |
| Changes in Estimated Future Development Costs | | 5,722 | (3,282) |
| Previously Estimated Development Costs Incurred | | 5,798 | 4,450 |
| Net Change in Income Taxes at Applicable Statutory Rate | | (10,075) | 82,966 |
| Revisions of Previous Quantity Estimates | | 34,998 | (15,478) |
| Accretion of Discount and Other | | 32,589 | 23,211 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | | | 74,249 |

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2007 | 2006 |
| | | (Thousands) | |
| **Total** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | 1,060,462 | 935,908 | 1,698,175 |
| Sales, Net of Production Costs | (455,825) | (311,110) | (360,323) |
| Net Changes in Prices, Net of Production Costs | 509,705 | 575,523 | (1,121,761) |
| Purchases of Minerals in Place | 67,768 | | 7,607 |
| Sales of Minerals in Place | (31,642) | (150,752) | (238) |
| Extensions and Discoveries | 143,394 | 105,659 | 77,344 |
| Changes in Estimated Future Development Costs | (100,684) | (77,477) | (87,032) |
| Previously Estimated Development Costs Incurred | 65,156 | 64,508 | 71,498 |
| Net Change in Income Taxes at Applicable Statutory Rate | (119,585) | (184,995) | 487,142 |
| Revisions of Previous Quantity Estimates | (3,936) | (105,205) | (10,628) |
| Accretion of Discount and Other | 133,031 | 208,403 | 174,124 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | $ 1,267,844 | $ 1,060,462 | $ 935,908 |

Schedule II Valuation and Qualifying Accounts

| Description | Balance at Beginning of Period | Additions Charged to Costs and Expenses | Additions Charged to Other Accounts(1) | Deductions(2) | Balance at End of Period |
|---|---|---|---|---|---|
| | | | (Thousands) | | |
| **Year Ended September 30, 2008** | | | | | |
| Allowance for Uncollectible Accounts | $ 28,654 | $ 27,274 | $ 2,734 | $ 25,545 | $ 33,117 |
| **Year Ended September 30, 2007** | | | | | |
| Allowance for Uncollectible Accounts | $ 31,427 | $ 27,652 | $ 1,414 | $ 31,839 | $ 28,654 |
| **Year Ended September 30, 2006** | | | | | |
| Allowance for Uncollectible Accounts | $ 26,940 | $ 29,088 | $ 907 | $ 25,508 | $ 31,427 |
| Deferred Tax Valuation Allowance | $ 2,877 | $ (2,877) | $ | $ | $ |

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

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

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

None

**Item 9A** ***Controls and Procedures***

**Evaluation of Disclosure Controls and Procedures**

The term disclosure controls and procedures is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company s management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company s management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company s disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company s Chief Executive Officer and Principal Financial Officer concluded that the Company s disclosure controls and procedures were effective as of September 30, 2008.

**Management s Report on Internal Control over Financial Reporting**

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

The Company s management assessed the effectiveness of the Company s internal control over financial reporting as of September 30, 2008. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control Integrated Framework.* Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2008.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company s consolidated financial statements included in this Annual Report on Form 10-K, has issued a report on the effectiveness of the Company s internal control over financial reporting as of September 30, 2008. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

**Changes in Internal Control over Financial Reporting**

There were no changes in the Company s internal control over financial reporting that occurred during the quarter ended September 30, 2008 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

**Item 9B** ***Other Information***

None

## PART III

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

The information required by this item concerning the directors of the Company and corporate governance is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2009

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Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2008. The information concerning directors is set forth in the definitive Proxy Statement under the headings entitled Nominees for Election as Directors for Three-Year Terms to Expire in 2012, Directors Whose Terms Expire in 2011, Directors Whose Terms Expire in 2010, and Section 16(a) Beneficial Ownership Reporting Compliance and is incorporated herein by reference. The information concerning corporate governance is set forth in the definitive Proxy Statement under the heading entitled Meetings of the Board of Directors and Standing Committees and is incorporated herein by reference. Information concerning the Company s executive officers can be found in Part I, Item 1, of this report.

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

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

**Item 11** ***Executive Compensation***

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2009 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2008. The information concerning executive compensation is set forth in the definitive Proxy Statement under the headings Executive Compensation and Compensation Committee Interlocks and Insider Participation and, excepting the Report of the Compensation Committee, is incorporated herein by reference.

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

**Equity Compensation Plan Information**

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2009 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2008. The equity compensation plan information is set forth in the definitive Proxy Statement under the heading Equity Compensation Plan Information and is incorporated herein by reference.

**Security Ownership and Changes in Control**

***(a) Security Ownership of Certain Beneficial Owners***

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2009 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2008. The information concerning security ownership of certain beneficial owners is set forth in the definitive Proxy Statement under the heading Security Ownership of Certain Beneficial Owners and Management and is incorporated herein by reference.

***(b) Security Ownership of Management***

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2009 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2008. The information concerning security ownership of management is set forth in the definitive Proxy Statement under the heading Security Ownership of Certain Beneficial Owners and Management and is incorporated herein by reference.

***(c) Changes in Control***

None

**Item 13** ***Certain Relationships and Related Transactions, and Director Independence***

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2009 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2008. The information regarding certain relationships and related transactions is set forth in the definitive Proxy Statement under the headings Compensation Committee Interlocks and Insider Participation and Related Person Transactions and is incorporated herein by reference. The information regarding director independence is set forth in the definitive Proxy Statement under the heading Director Independence and is incorporated herein by reference.

**Item 14** ***Principal Accountant Fees and Services***

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its 2009 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2008. The information concerning principal accountant fees and services is set forth in the definitive Proxy Statement under the heading Audit Fees and is incorporated herein by reference.

## PART IV

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

**(a)1. Financial Statements**

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

**(a)2. Financial Statement Schedules**

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

**(a)3. Exhibits**

| Exhibit Number | Description of Exhibits |
|---|---|
| 3(i) | Articles of Incorporation:<br>Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)<br>Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 3(ii), Form 8-K dated March 14, 2005 in File No. 1-3880) |

| | |
|---|---|
| 3(ii) | By-Laws: |
| | National Fuel Gas Company By-Laws as amended June 11, 2008 (Exhibit 3.1, Form 8-K dated June 16, 2008 in File No. 1-3880) |
| 4 | Instruments Defining the Rights of Security Holders, Including Indentures: |
| | Indenture, dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796) |

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| Exhibit Number | Description of Exhibits |
|---|---|
| | Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401) |
| | Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992 in File No. 1-3880) |
| | Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992 in File No. 1-3880) |
| | Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401) |
| | Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993 in File No. 1-3880) |
| | Fifteenth Supplemental Indenture, dated as of September 1, 1996, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880) |
| | Indenture dated as of October 1, 1999, between the Company and The Bank of New York (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880) |
| | Officers Certificate Establishing Medium-Term Notes, dated October 14, 1999 (Exhibit 4.2, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880) |
| | Officers Certificate establishing 5.25% Notes due 2013, dated February 18, 2003 (Exhibit 4, Form 10-Q for the quarterly period ended March 31, 2003 in File No. 1-3880) |
| | Officer s Certificate establishing 6.50% Notes due 2018, dated April 11, 2008 (Exhibit 4.1, Form 10-Q for the quarterly period ended June 30, 2008 in File No. 1-3880) |
| | Amended and Restated Rights Agreement, dated as of July 11, 2008, between the Company and The Bank of New York, as rights agent (Exhibit 4.1, Form 8-K dated July 15, 2008 in File No. 1-3880) |
| 10 | Material Contracts: |
| | Credit Agreement, dated as of August 19, 2005, among the Company, the Lenders Party Thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| | Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006 in File No. 1-3880) |
| | Settlement Agreement dated January 24, 2008 among the Company, New Mountain Vantage GP, L.L.C. ( Vantage ) and certain of Vantage s affiliates (Exhibit 10.1, Form 8-K dated January 24, 2008 in File No. 1-3880) |
| | Director Services Agreement, dated as of June 1, 2008, between the Company and Philip C. Ackerman (Exhibit 99, Form 8-K dated June 16, 2008 in File No. 1-3880) |
| | Resolutions adopted by the National Fuel Gas Company Board of Directors on February 21, 2008 regarding director stock ownership guidelines (Exhibit 10.5, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880) |
| 10.1 | Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of Karen M. Camiolo, Carl M. Carlotti, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith |

| | |
|---|---|
| | and Ronald J. Tanski |
| 10.2 | Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, Seneca Resources Corporation and Matthew D. Cabell |
| | Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |

| Exhibit Number | Description of Exhibits |
|---|---|
| | National Fuel Gas Company 1993 Award and Option Plan, dated February 18, 1993 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880) |
| | Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated October 27, 1995 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880) |
| | Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 11, 1996 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880) |
| | Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 18, 1996 (Exhibit 10, Form 10-Q for the quarterly period ended December 31, 1996 in File No. 1-3880) |
| | National Fuel Gas Company 1993 Award and Option Plan, amended through June 14, 2001 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880) |
| | National Fuel Gas Company 1993 Award and Option Plan, amended through September 8, 2005 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| | Administrative Rules with Respect to At Risk Awards under the 1993 Award and Option Plan (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880) |
| | National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880) |
| | Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005 in File No. 1-3880) |
| | Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006 in File No. 1-3880) |
| | Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |
| | Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |
| | Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880) |
| | Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| 10.3 | Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program |
| | Description of performance goals for certain executive officers under the Company s Annual At Risk Compensation Incentive Program (Exhibit 10.8, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |
| | Description of performance goals for certain executive officers under the Company s Annual At Risk Compensation Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2007 in File No. 1-3880) |
| 10.4 | National Fuel Gas Company Executive Annual Cash Incentive Program |
| | Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective February 20, 2008 (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880) |
| | National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994 in File No. 1-3880) |
| | Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880) |

Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)

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| Exhibit Number | Description of Exhibits |
| --- | --- |
| | National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880) |
| | Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880) |
| | Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880) |
| | Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880) |
| | Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880) |
| | Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| | Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| | National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997 in File No. 1-3880) |
| | Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880) |
| | Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880) |
| | Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| | National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005 in File No. 1-3880) |
| | National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880) |
| | Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880) |
| | Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880) |
| | Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880) |
| | Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880) |
| | National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880) |
| | National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880) |
| | Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997 in File |

No. 1-3880)
Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)

| Exhibit Number | Description of Exhibits |
|---|---|
| | Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880) |
| | Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001, in File No. 1-3880) |
| | National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |
| | National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007 (Exhibit 10.4, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880) |
| 10.5 | National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 |
| | National Fuel Gas Company and Participating Subsidiaries 1996 Executive Retirement Plan Trust Agreement (II), dated May 10, 1996 (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880) |
| | National Fuel Gas Company Participating Subsidiaries Executive Retirement Plan 2003 Trust Agreement (I), dated September 1, 2003 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880) |
| | National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 8-K dated June 3, 2005 in File No. 1-3880) |
| | Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of March 20, 1997 regarding the Retainer Policy for Non-Employee Directors (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880) |
| | Amended and Restated Retirement Benefit Agreement for David F. Smith, dated September 20, 2007, among the Company, National Fuel Gas Supply Corporation and David F. Smith (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2007 in File No. 1-3880) |
| | Description of assignment of interests in certain life insurance policies (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880) |
| | Description of long-term performance incentives under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.7, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |
| | Description of long-term performance incentives under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2008 in File No. 1-3880) |
| | Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880) |
| | Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006 in File No. 1-3880) |
| 12 | Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2004 through 2008 |
| 21 | Subsidiaries of the Registrant |
| 23 | Consents of Experts: |
| 23.1 | Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation |

| | |
|---|---|
| 23.2 | Consent of Independent Registered Public Accounting Firm |
| 31 | Rule 13a-14(a)/15d-14(a) Certifications: |
| 31.1 | Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act |

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| Exhibit Number | Description of Exhibits |
|---|---|
| 31.2 | Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act |
| 32 | Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 99 | Additional Exhibits: |
| 99.1 | Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation |
| 99.2 | Company Maps |
| | Incorporated herein by reference as indicated. |
| | All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K |
| | In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management s Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is furnished and not deemed filed with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference |

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## Signatures

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

**National Fuel Gas Company**
**(Registrant)**

By /s/ D. F. Smith
D. F. Smith
President and Chief Executive Officer

Date: November 26, 2008

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

| Signature | Title | |
|---|---|---|
| /s/ P. C. Ackerman | Chairman of the Board and Director | Date: November 26, 2008 |
| P. C. Ackerman | | |
| /s/ R. T. Brady | Director | Date: November 26, 2008 |
| R. T. Brady | | |
| /s/ R. D. Cash | Director | Date: November 26, 2008 |
| R. D. Cash | | |
| /s/ S. E. Ewing | Director | Date: November 26, 2008 |
| S. E. Ewing | | |
| /s/ R. E. Kidder | Director | Date: November 26, 2008 |
| R. E. Kidder | | |
| /s/ C. G. Matthews | Director | Date: November 26, 2008 |
| C. G. Matthews | | |
| /s/ G. L. Mazanec | Director | Date: November 26, 2008 |

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|---|---|---|
| G. L. Mazanec | | |
| /s/ R. G. Reiten | Director | Date: November 26, 2008 |
| R. G. Reiten | | |
| /s/ F. V. Salerno | Director | Date: November 26, 2008 |
| F. V. Salerno | | |
| /s/ D. F. Smith | President, Chief Executive Officer and Director | Date: November 26, 2008 |
| D. F. Smith | | |

| Signature | Title | |
|---|---|---|
| /s/ R. J. Tanski<br>R. J. Tanski | Treasurer and Principal Financial Officer | Date: November 26, 2008 |
| /s/ K. M. Camiolo<br>K. M. Camiolo | Controller and Principal Accounting Officer | Date: November 26, 2008 |