NATIONAL FUEL GAS CO
Form 10-K
December 08, 2006

Table of Contents

**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, 2006**

**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, or a non-accelerated filer. See definition of accelerated filer and large accelerated filer in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer þ Accelerated Filer o Non-Accelerated Filer 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 $2,715,600,700 as of March 31, 2006.

Common Stock, $1 Par Value, outstanding as of November 30, 2006: 82,385,144 shares.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant s definitive Proxy Statement for the Annual Meeting of Shareholders to be held February 15, 2007 are incorporated by reference into Part III of this report.

Table of Contents

**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.

**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

**NYPSC** State of New York Public Service Commission

**PaPUC** Pennsylvania Public Utility Commission

**SEC** Securities and Exchange Commission

**NTSB** National Transportation Safety Board

***Other***

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

**APB 20** Accounting Principles Board Opinion No. 20, Accounting Changes

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

**Bbl** Barrel (of oil)

**Bcf** Billion cubic feet (of natural gas)

**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.

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

**CTA** Cumulative Foreign Currency Translation Adjustment

**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.

**Energy Policy Act** Energy Policy Act of 2005

**Exchange Act** Securities Exchange Act of 1934, as amended

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

**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.

**Heavy oil** A type of crude petroleum that usually is not economically recoverable in its natural state without being heated or diluted.

**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.

**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.

**Order 667-A** An order issued by FERC to clarify Order 667 entitled Repeal of the Public Utility Holding Company Act of 1935 and Enactment of the Public Utility Holding Company Act of 2005.

**Precedent Agreement** An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called conditions precedent ) happen, usually within a specified time.

**Proved developed reserves** Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

**Proved undeveloped reserves** Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make 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.

**SFAS** Statement of Financial Accounting Standards

**SFAS 3** Statement of Financial Accounting Standards No. 3, Reporting Accounting Changes in Interim Financial Statements

**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 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 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 154** Statement of Financial Accounting Standards No. 154, Accounting Changes and Error Corrections

**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

**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.

Table of Contents

**For the Fiscal Year Ended September 30, 2006**

## CONTENTS

1

Table of Contents

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, those statements that are designated with an asterisk ( * ) following the statement, as well as those statements that are identified by the use of the words anticipates, estimates, expects, intends, plans, predicts, projects, and similar expressions.

## PART I

### Item 1 *Business*

### The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), incorporated in 1902, is a holding company organized under the laws of the State of New Jersey. Except as otherwise indicated below, the Registrant owns directly or indirectly all of the outstanding securities of its subsidiaries. Reference to the Company in this report means the Registrant, the Registrant and its subsidiaries or the Registrant s subsidiaries as appropriate in the context of the disclosure. Also, all references to a certain year in this report relate to the Company s fiscal year ended September 30 of that year unless otherwise noted.

The Company is a diversified energy company consisting of five reportable 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) 28 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 various other interstate gas pipeline companies. Empire, an intrastate pipeline company, transports natural gas for Distribution Corporation and for other utilities, large industrial customers and power producers in New York State. Empire owns 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. The Company acquired Empire in February 2003.

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, and in the Gulf Coast region of Texas, Louisiana, and Alabama, including offshore areas in federal waters and some state waters. Also, Exploration and Production operations are conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada by Seneca Energy Canada Inc. (SECI), an Alberta, Canada corporation and a subsidiary of Seneca. At September 30, 2006, the Company had U.S. and Canadian reserves of 58,018 Mbbl of oil and 232,575 MMcf of natural gas.

4. The Energy Marketing segment operations are carried out by National Fuel Resources, Inc. (NFR), a New York corporation, which markets natural gas to industrial, commercial, public authority and residential end-users in western and central New York and northwestern Pennsylvania, offering competitively priced energy and energy management services for its customers.

Table of Contents

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, 2006, the Company owned approximately 100,000 acres of timber property and managed an additional 4,000 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 reportable 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; and

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 ).*

No single customer, or group of customers under common control, accounted for more than 10% of the Company s consolidated revenues in 2006.

**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. On October 11, 2005, Empire

Table of Contents

filed an application with the FERC for the authority to build and operate an extension of its natural gas pipeline (the Empire Connector). If the FERC grants that application and the Company builds and commences operations of the Empire Connector, Empire will at that time become a FERC-regulated pipeline company.* 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 36.1% of the Company s 2006 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 40.3% of the Company s 2006 net income available for common stock.

Supply Corporation has service agreements for all of its firm storage capacity, which totals approximately 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 3,888 MDth or 5.7% of the total firm storage capacity. Nonaffiliated customers have contracted for the remaining 36,655 MDth or 53.6% of the total firm storage capacity. Following an industry trend, most 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 2007, 95.9% of Supply Corporation s total firm storage capacity was committed under contracts that, subject to 2006 shipper or Supply Corporation notifications, could have been terminated effective in 2007. Supply Corporation neither issued nor received any contract termination notices in 2006, however, so it does not expect any storage contract terminations effective in 2007.* In 2006, the increased value of market-area storage afforded Supply Corporation the opportunity to eliminate a significant number of monetary rate discounts and to sign certain multi-year primary term extensions.

Supply Corporation s firm transportation capacity is not 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 1,995 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,092 MDth per day or 54.7% of contracted transportation capacity, and the Energy Marketing segment represents another 99 MDth per day or 5.0% of contracted transportation capacity. The remaining 804 MDth or 40.3% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

Table of Contents

At the beginning of 2007, 56.9% of Supply Corporation s contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2007 or, subject to 2006 shipper or Supply Corporation notifications, could have been terminated effective in 2007. Based on contract expirations and termination notices received in 2006 for 2007 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to decrease 0.8% in 2007.* Similarly, 28.4% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2007 or, subject to 2006 shipper or Supply Corporation notifications, could have been terminated effective in 2007. Based on contract expirations and termination notices received in 2006 for 2007 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to decrease 2.4% in 2007.* Supply Corporation previously has been successful in marketing and obtaining executed contracts for available transportation capacity (at discounted rates when necessary), and expects its success to continue.*

Empire has service agreements for the 2006-2007 winter period for all of its firm transportation capacity, which totals approximately 575 MDth per day. Empire provides service under both annual (12 months per year) and seasonal (winter or summer only) contracts. Approximately 88.7% of Empire s firm contracted capacity is on an annual long-term basis. Annual long-term agreements representing 0.5% of Empire s firm contracted capacity expire in 2007. Approximately 3.4% of Empire s firm contracted capacity is under multi-year seasonal contracts, none of which expire in 2007. The remaining capacity, which represents 7.9% of Empire s firm contracted capacity, is under single season or annual contracts which will expire before the end of 2007. Empire expects that all of this expiring capacity will be re-contracted under seasonal and/or annual arrangements for future contracting periods.* The Utility segment accounts for approximately 8.6% of Empire s firm contracted capacity, and the Energy Marketing segment accounts for approximately 1.7% of Empire s firm contracted capacity, with the remaining 89.7% of Empire s firm contracted transportation capacity subject to contracts with nonaffiliated customers.

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

**The Exploration and Production Segment**

The Exploration and Production segment contributed approximately 15.2% of the Company s 2006 net income available for common stock.

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

**The Energy Marketing Segment**

The Energy Marketing segment contributed approximately 4.2% of the Company s 2006 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 contributed approximately 4.1% of the Company s 2006 net income available for common stock.

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.

Table of Contents

**All Other Category and Corporate Operations**

The All Other category and Corporate operations contributed less than 1% of the Company s 2006 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 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 2006, the Utility segment purchased 74.5 Bcf of gas for core market demand. Gas purchased from producers and suppliers in the southwestern United States and Canada under firm contracts (seasonal and longer) accounted for 82% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 18% of the Utility segment s 2006 purchases. Purchases from Chevron Natural Gas (16%), ConocoPhillips Company (15%), Total Gas & Power North America Inc. (11%) and Anadarko Energy Services Company (11%) accounted for 53% of the Utility s 2006 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2006.

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-five percent of the timber processed during 2006 in Highland s sawmill operations came from land owned by the Company s subsidiaries, and 45% came from outside sources. In addition, Highland purchased approximately eight 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 2006, this segment purchased 47 Bcf of natural gas, of which 45 Bcf served core market demands. The remaining 2 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, the NYPSC has stepped up its efforts to encourage customer choice at the retail residential level. 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. In 2006, the PaPUC reconvened a stakeholder group to explore ways to increase the participation of retail customers in choice programs. The findings of the stakeholder group are expected to be presented to the PaPUC during 2007.

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.*

The Utility segment competes, through its unbundled flexible services, in its most vulnerable markets (the large commercial and industrial markets).* The Utility segment continues to (i) develop or promote new sources and uses of natural gas or new services, rates and contracts and (ii) emphasize and provide 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 particularly 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 pursuing the Empire Connector project, which would expand its natural gas pipeline 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.

8

**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, each of Seneca and SECI 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 management services. 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 hardwoods 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 more than 2.2% warmer than normal results in a surcharge being added to customers current bills, while weather that is more than 2.2% 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, and can have a moderate effect on its revenues. Empire s allowed rates 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.

Variations in weather conditions can materially affect the volume of gas consumed by customers of the Energy Marketing segment. Volume variations can 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 out lower-grade or lower value trees from the 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 1,993 full-time employees at September 30, 2006, with 1,970 employees in all of its U.S. operations and 23 employees in its Canadian operations at SECI. This is a decrease of 2.5% from the 2,044 total employed at September 30, 2005.

Agreements covering employees in collective bargaining units in New York are scheduled to expire in February 2008. Certain agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2009, and other agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in May 2009.

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

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

**Executive Officers of the Company as of November 15, 2006 (except as otherwise noted)(1)**

| **Name and Age (as of November 15, 2006)** | **Current Company Positions and Other Material Business Experience During Past Five Years** |
|---|---|
| Philip C. Ackerman (62) | Chairman of the Board of Directors since January 2002; Chief Executive Officer since October 2001; and President of Horizon since September 1995. Mr. Ackerman has served as a Director of the Company since March 1994, and previously served as President of the Company from July 1999 through January 2006. |

| | |
|---|---|
| David F. Smith (53) | President of the Company since February 2006; Chief Operating Officer of the Company since February 2006; President of Supply Corporation since April 2005; President of Empire since April 2005. Mr. Smith previously served as 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. |

Table of Contents

| Name and Age (as of November 15, 2006) | Current Company Positions and Other Material Business Experience During Past Five Years |
|---|---|
| Ronald J. Tanski (54) | Treasurer and Principal Financial Officer of the Company since April 2004; President of Distribution Corporation since February 2006; Treasurer of Distribution Corporation since April 2004; Secretary and Treasurer of Supply Corporation since April 2004; Secretary and Treasurer of Horizon since February 1997. Mr. Tanski previously served as 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 (48) | President of Seneca effective December 11, 2006. Mr. Cabell previously served as Executive Vice President and General Manager of Marubeni Oil & Gas (USA) Inc., an exploration and production company with assets of over $1,000,000,000, as Vice President of Randall & Dewey, Inc., a major oil and gas transaction advisory firm, as an independent consultant assisting oil companies in upstream acquisition and divestment transactions as well as Gulf of Mexico entry strategy, and as Vice President, Gulf of Mexico Exploration for Texaco Corporation. Mr. Cabell s prior employers are not subsidiaries or affiliates of the Company. |
| Karen M. Camiolo (47) | 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. |
| Anna Marie Cellino (53) | Secretary of the Company since October 1995; Senior Vice President of Distribution Corporation since July 2001. |
| Paula M. Ciprich (46) | General Counsel of the Company since January 2005; Assistant Secretary and General Counsel of Distribution Corporation since February 1997. |
| Donna L. DeCarolis (47) | President of NFR since January 2005; Secretary of NFR since March 2002; Vice President of NFR from May 2001 to January 2005. |
| John R. Pustulka (54) | Senior Vice President of Supply Corporation since July 2001. |
| James D. Ramsdell (51) | 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.

11

## 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.

***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 has relied, and continues to rely, upon shorter term bank borrowings and commercial paper to finance the execution of a portion of its operating strategies. National Fuel is dependent on these capital sources to provide capital to its subsidiaries to allow them to acquire 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. 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. National Fuel has no active interest rate hedges in place with respect to other debt except at the project level of Empire, where there is an interest rate collar on the approximate $22.8 million of project debt (at September 30, 2006). 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, Moody s Investors Service and Fitch Ratings Service. A ratings downgrade could increase the interest cost of this debt and decrease future availability of money from banks, commercial paper purchasers and other sources. National Fuel believes it is important to maintain investment grade credit ratings to conduct its business.

***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. The purpose of the law was to permit consumer choice of natural gas suppliers. To a certain degree, the early programs instituted to comply with the Act have not been overly successful, 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. The PaPUC has reconvened a stakeholder group to explore ways to increase the participation of retail customers in choice programs. 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. These new forms of regulation 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.

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. (On October 11, 2005, Empire filed an application with the FERC for the authority to build and operate an extension of its natural gas pipeline (the Empire Connector). If the FERC grants that application and the Company builds 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 National Fuel expects to do so in the future.* 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.

***Uncertain economic conditions 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 upon general economic conditions in the capital markets. 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 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.***

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 70% 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, under the applicable accounting rules, such 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, and assumptions regarding the levels of production that will be achieved. 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 hedge prices exceed market prices, and losses would occur to the extent that market prices exceed hedge prices.

Use of energy commodity price hedges also exposes National Fuel to the risk of non-performance by a contract counterparty. National Fuel carefully evaluates the financial strength of all contract counterparties, but 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 be strictly confined to the price hedging of existing and forecast production, and National Fuel maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades could occur that may expose National Fuel to substantial losses to cover positions in these contracts. In addition, in the event actual production 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 future reserve estimates. 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 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 natural gas can be unprofitable, not only from dry 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, on a country-by-country basis, 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. If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future revenues, 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. The event that had the most significant impact in 2006, and the main reason for the significant earnings decrease over 2005, was the Exploration and Production segment recording after-tax impairment charges totaling $68.6 million related to its Canadian oil and gas assets during 2006 under the full cost method of accounting. 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 (including those of Canada) 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 are subject to inherent hazards and risks such as: fires; natural disasters; explosions; formations with abnormal pressures; blowouts; 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 large insurance losses caused by Hurricanes Katrina and Rita in 2005, the insurance industry has significantly increased premiums for insurance on Gulf of Mexico properties, and has reduced the limits typically available for windstorm damage. As a result, National Fuel has determined that it is not economical to purchase insurance to fully cover its exposures in the Gulf of Mexico in the event of a named windstorm. National Fuel has procured named windstorm coverage in an amount equal to approximately three times the estimated physical damage loss sustained by National Fuel as a result of named windstorms during the 2005 hurricane season, subject to a deductible of $2 million per occurrence. No assurance can be given, however, that such amount will be sufficient to cover losses that may occur in the future.

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.

***National Fuel may be adversely affected by economic conditions.***

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 also impact its collections of accounts receivable.

## Item 1B *Unresolved Staff Comments*

None

## Item 2 *Properties*

### General Information on Facilities

The investment of the Company in net property, plant and equipment was $2.9 billion at September 30, 2006. Approximately 61% 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, in the Gulf Coast region of Texas, Louisiana, and Alabama and in the provinces of Alberta, Saskatchewan and British Columbia in Canada. The remaining investment in net property, plant and equipment consisted primarily of the Timber segment (3%) 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 $97.0 million, or 3.5%, since 2001. 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, 2006. The net investment in its gas distribution network (including 14,809 miles of distribution pipeline) and its service connections to customers represent approximately 53% and 33%, respectively, of the Utility segment s net investment in property, plant and equipment at September 30, 2006.

The Pipeline and Storage segment had a net investment of $674.2 million in property, plant and equipment at September 30, 2006. Transmission pipeline represents 36% of this segment s total net investment and includes 2,528 miles of pipeline required to move large volumes of gas throughout its service area. Storage facilities represent 24% of this segment s total net investment and consist of 32 storage fields, four of which are jointly owned and operated with certain pipeline suppliers, and 439 miles of pipeline. Net investment in storage facilities includes $93.8 million of gas stored underground-noncurrent, representing the cost of the gas required 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 28 compressor stations with 75,361 installed compressor horsepower that represent 13% of this segment s total net investment in property, plant and equipment.

The Exploration and Production segment had a net investment in property, plant and equipment of $1.0 billion at September 30, 2006. Of this amount, $914.2 million relates to properties located in the United States. The remaining net investment of $88.0 million relates to properties located in Canada.

The Timber segment had a net investment in property, plant and equipment of $90.9 million at September 30, 2006. Located primarily in northwestern Pennsylvania, the net investment includes two sawmills, approximately 100,000 acres of land and timber, and approximately 4,000 acres of timber rights.

The Utility and Pipeline and Storage segments facilities provided the capacity to meet the Company s 2006 peak day sendout, including transportation service, of 1,542.4 MMcf, which occurred on February 18, 2006. Withdrawals from storage of 545.2 MMcf provided approximately 35.3% of the requirements on that day.

Company maps are included in exhibit 99.3 of this Form 10-K and are incorporated herein by reference.

**Exploration and Production Activities**

The Company is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in the Gulf Coast region of Texas, Louisiana, and Alabama. Also, Exploration and Production operations are conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada. 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 decreased from 238 Bcf at September 30, 2005 to 233 Bcf at September 30, 2006. This decrease can be attributed primarily to production and downward reserve revisions related primarily to the Canadian properties. These decreases were partially offset by extensions and discoveries. The downward reserve revisions were largely a function of a significant decrease in gas prices during the fourth quarter of 2006. Seneca s proved developed and undeveloped oil reserves decreased from 60,257 Mbbl at September 30, 2005 to 58,018 Mbbl at September 30, 2006. This decrease can be attributed mostly to production. Seneca s proved developed and undeveloped natural gas reserves increased from 225 Bcf at September 30, 2004 to 238 Bcf at September 30, 2005. This increase can be attributed to the fact that net extensions and discoveries outpaced production. However, Seneca s proved developed and undeveloped oil reserves decreased from 65,213 Mbbl at September 30, 2004 to 60,257 Mbbl at September 30, 2005. This decrease can be attributed to the fact that production outpaced net extensions and discoveries.

Seneca s oil and gas reserves reported in Note O as of September 30, 2006 were estimated by Seneca s geologists and engineers and were audited by independent petroleum engineers from Ralph E. Davis 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 basis of reporting Seneca s reserves to the EIA is identical to that reported in Note O.

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 | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| **United States** | | | |
| Gulf Coast Region | | | |
| Average Sales Price per Mcf of Gas | $ 8.01 | $ 7.05 | $ 5.61 |
| Average Sales Price per Barrel of Oil | $ 64.10 | $ 49.78 | $ 35.31 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 5.89 | $ 6.01 | $ 4.82 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 47.46 | $ 35.03 | $ 31.51 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 0.86 | $ 0.71 | $ 0.60 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 36 | 50 | 73 |
| West Coast Region | | | |
| Average Sales Price per Mcf of Gas | $ 7.93 | $ 6.85 | $ 5.54 |
| Average Sales Price per Barrel of Oil | $ 56.80 | $ 42.91 | $ 31.89 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 7.19 | $ 6.15 | $ 5.72 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 37.69 | $ 23.01 | $ 22.86 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.35 | $ 1.15 | $ 1.05 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 53 | 53 | 55 |
| Appalachian Region | | | |
| Average Sales Price per Mcf of Gas | $ 9.53 | $ 7.60 | $ 5.91 |
| Average Sales Price per Barrel of Oil | $ 65.28 | $ 48.28 | $ 31.30 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 8.90 | $ 7.01 | $ 5.72 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 65.28 | $ 48.28 | $ 31.30 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 0.69 | $ 0.63 | $ 0.54 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 15 | 13 | 14 |
| **Total United States** | | | |
| Average Sales Price per Mcf of Gas | $ 8.42 | $ 7.13 | $ 5.66 |
| Average Sales Price per Barrel of Oil | $ 58.47 | $ 44.87 | $ 33.13 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 7.02 | $ 6.26 | $ 5.13 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 40.26 | $ 26.59 | $ 26.06 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.09 | $ 0.90 | $ 0.76 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 104 | 117 | 142 |

Table of Contents

| | For the Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| **Canada** | | | |
| Average Sales Price per Mcf of Gas | $ 7.14 | $ 6.15 | $ 4.87 |
| Average Sales Price per Barrel of Oil | $ 51.40 | $ 42.97 | $ 30.94 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 7.47 | $ 6.14 | $ 4.79 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 51.40 | $ 42.97 | $ 30.94 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.57 | $ 1.29 | $ 1.00 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 26 | 27 | 22 |
| **Total Company** | | | |
| Average Sales Price per Mcf of Gas | $ 8.04 | $ 6.86 | $ 5.51 |
| Average Sales Price per Barrel of Oil | $ 57.94 | $ 44.72 | $ 32.98 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 7.15 | $ 6.23 | $ 5.06 |
| Average Sales Price per Barrel of Oil (after hedging) | $ 41.10 | $ 27.86 | $ 26.40 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.18 | $ 0.98 | $ 0.80 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 130 | 144 | 164 |

**Productive Wells**

| | | United States | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Gulf Coast Region | | West Coast Region | | Appalachian Region | | Total U.S. | |
| **At September 30, 2006** | | Gas | Oil | Gas | Oil | Gas | Oil | Gas | Oil |
| Productive Wells | Gross | 34 | 30 | | 1,274 | 2,138 | 31 | 2,172 | 1,335 |
| Productive Wells | Net | 21 | 14 | | 1,266 | 2,052 | 25 | 2,073 | 1,305 |

**Productive Wells**

| | | Canada | | Total Company | |
|---|---|---|---|---|---|
| **At September 30, 2006** | | Gas | Oil | Gas | Oil |
| Productive Wells | Gross | 217 | 53 | 2,389 | 1,388 |
| Productive Wells | Net | 155 | 36 | 2,228 | 1,341 |

**Developed and Undeveloped Acreage**

| | United States | | | | | |
|---|---|---|---|---|---|---|
| **At September 30, 2006** | Golf Coast Region | West Coast Region | Appalachian Region | Total U.S. | Canada | Total Company |

| | | | | | | |
|---|---|---|---|---|---|---|
| Developed Acreage | | | | | | |
| Gross | 144,610 | 10,479 | 514,222 | 669,311 | 117,955 | 787,266 |
| Net | 104,173 | 10,109 | 487,384 | 601,666 | 84,182 | 685,848 |
| Undeveloped Acreage | | | | | | |
| Gross | 174,503 | | 475,909 | 650,412 | 393,169 | 1,043,581 |
| Net | 85,117 | | 451,733 | 536,850 | 243,287 | 780,137 |

As of September 30, 2006, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 191,159 acres in 2007 (128,900 net acres), 112,156 acres in 2008 (65,174 net acres), 83,246 acres in 2009 (57,538 net acres), and 657,020 acres thereafter (528,525 net acres).

Table of Contents

**Drilling Activity**

| For the Year Ended September 30 | Productive 2006 | 2005 | 2004 | Dry 2006 | 2005 | 2004 |
|---|---|---|---|---|---|---|
| **United States** | | | | | | |
| Gulf Coast Region | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | 2.94 | 1.30 | | 0.85 | 0.47 | 0.50 |
| Development | 0.78 | 0.23 | 0.65 | | | |
| West Coast Region Net Wells Completed | | | | | | |
| Exploratory | | | | | | |
| Development | 92.98 | 116.97 | 49.00 | 1.00 | | |
| Appalachian Region Net Wells Completed | | | | | | |
| Exploratory | 3.88 | 3.00 | | | 4.00 | 3.00 |
| Development | 140.58 | 45.00 | 41.00 | 1.75 | 1.00 | |
| Total United States Net Wells Completed | | | | | | |
| Exploratory | 6.82 | 4.30 | | 0.85 | 4.47 | 3.50 |
| Development | 234.34 | 162.20 | 90.65 | 2.75 | 1.00 | |
| **Canada** | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | 12.60 | 21.14 | 52.85 | 1.35 | 2.00 | 6.08 |
| Development | 2.50 | 3.50 | 10.50 | 1.00 | | |
| **Total** | | | | | | |
| Net Wells Completed | | | | | | |
| Exploratory | 19.42 | 25.44 | 52.85 | 2.20 | 6.47 | 9.58 |
| Development | 236.84 | 165.70 | 101.15 | 3.75 | 1.00 | |

**Present Activities**

| At September 30, 2006 | United States Gulf Coast Region | West Coast Region | Appalachian Region | Total U.S. | Canada | Total Company |
|---|---|---|---|---|---|---|
| Wells in Process of Drilling(1) | | | | | | |
| Gross | 5.00 | 6.00 | 54.00 | 65.00 | 5.00 | 70.00 |
| Net | 2.69 | 5.50 | 54.00 | 62.19 | 2.13 | 64.32 |

(1) Includes wells awaiting completion.

**Item 3** ***Legal Proceedings***

In an action instituted in the New York State Supreme Court, Kings County on February 18, 2003 against Distribution Corporation and Paul J. Hissin, an unaffiliated third party, plaintiff Donna Fordham-Coleman, as administratrix of the estate of Velma Arlene Fordham, alleges that Distribution Corporation s denial of natural gas service in November

2000 to the plaintiff s decedent, Velma Arlene Fordham, caused the decedent s death in February 2001. The plaintiff sought damages for wrongful death and pain and suffering, plus punitive damages. Distribution Corporation denied plaintiff s material allegations, asserted seven affirmative defenses and asserted a cross-claim against the co-defendant. Distribution Corporation believes, and has vigorously asserted, that plaintiff s allegations lack merit. The Court changed venue of the action to New York State Supreme Court, Erie County. Discovery closed in October 2005, and Distribution Corporation filed a motion for summary judgment in November 2005. On February 24, 2006, the Court granted Distribution Corporation s motion for summary

Table of Contents

judgment dismissing plaintiff s claims for wrongful death and punitive damages. The Court denied Distribution Corporation s motion for summary judgment to dismiss plaintiff s negligence claim seeking recovery for conscious pain and suffering. On March 15, 2006, the plaintiff appealed the Court s decision to the New York State Supreme Court, Appellate Division, Fourth Department. On March 29, 2006, Distribution Corporation filed a cross-appeal. A trial date is scheduled for October 15, 2007 (although it is possible that the Court may change that date or that a trial may become unnecessary, based on the progress or outcome of the pending appeals).

On April 7, 2006, the NYPSC, PaPUC and Pennsylvania Office of Consumer Advocate filed a complaint and a motion for summary disposition against Supply Corporation with the FERC under Sections 5(a) and 13 of the Natural Gas Act. For a discussion of these matters, refer to Part II, Item 7 MD&A of this report under the heading Other Matters Rate and Regulatory Matters.

On June 8, 2006, the NTSB issued safety recommendations to Distribution Corporation, the PaPUC and certain others as a result of its investigation of a natural gas explosion that occurred on Distribution Corporation s system in Dubois, Pennsylvania in August 2004. For a discussion of this matter, refer to Part II, Item 7 MD&A of this report under the heading Other Matters Rate and Regulatory Matters.

The Company believes, based on the information presently known, that the ultimate resolution of the above matters will not be material to the consolidated financial condition, results of operations, or cash flow of the Company.* No assurances can be given, however, as to the ultimate outcome of these matters, and it is possible that the outcome could be material to results of operations or cash flow for a particular quarter or annual period.*

For a discussion of various environmental and other matters, refer to Item 7, MD&A and Item 8 at Note H Commitments and Contingencies.

In addition to the matters disclosed above, 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 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, 2006.

## 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 1, 2006, the Company issued a total of 2,100 unregistered shares of Company common stock to the seven non-employee directors of the Company serving on the Board of 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, 2006, pursuant to the Company s Retainer Policy for Non-Employee Directors. These transactions were exempt from registration under Section 4(2) of the Securities Act of 1933, as transactions not involving a public offering.

Table of Contents

**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, 2006 | 444,198 | $ 36.32 | 94,400 | 5,621,250 |
| Aug. 1-31, 2006 | 47,155 | $ 37.91 | | 5,621,250 |
| Sept. 1-30, 2006 | 192,702 | $ 36.46 | 147,800 | 5,473,450 |
| Total | 684,055 | $ 36.47 | 242,200 | 5,473,450 |

(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 349,798 in July 2006, 47,155 in August 2006 and 44,902 in September 2006 (a three month total of 441,855). Of those shares, 27,499 were purchased for the Company s 401(k) plans and 414,356 were purchased as a result of shares tendered to the Company by holders of stock options or shares of restricted stock.

(b) On December 8, 2005, the Company s Board of Directors authorized the repurchase of up to eight million shares of the Company s common stock. Repurchases may be made from time to time in the open market or through private transactions.

**Item 6** ***Selected Financial Data(1)***

| | Year Ended September 30 | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 (Thousands) | 2003 | 2002 |
| **Summary of Operations** | | | | | |
| Operating Revenues | $ 2,311,659 | $ 1,923,549 | $ 1,907,968 | $ 1,921,573 | $ 1,369,869 |
| Operating Expenses: | | | | | |
| Purchased Gas | 1,267,562 | 959,827 | 949,452 | 963,567 | 462,857 |

| | | | | | |
|---|---|---|---|---|---|
| Operation and Maintenance | 413,726 | 404,517 | 385,519 | 361,898 | 372,063 |
| Property, Franchise and Other Taxes | 69,942 | 69,076 | 68,978 | 79,692 | 69,837 |
| Depreciation, Depletion and Amortization | 179,615 | 179,767 | 174,289 | 181,329 | 168,745 |
| Impairment of Oil and Gas Producing Properties | 104,739 | | | 42,774 | |
| | 2,035,584 | 1,613,187 | 1,578,238 | 1,629,260 | 1,073,502 |
| Gain (Loss) on Sale of Timber Properties | | | (1,252) | 168,787 | |
| Gain (Loss) on Sale of Oil and Gas Producing Properties | | | 4,645 | (58,472) | |
| Operating Income | 276,075 | 310,362 | 333,123 | 402,628 | 296,367 |

**Table of Contents**

| | Year Ended September 30 | | | | |
|---|---|---|---|---|---|
| | **2006** | **2005** | **2004** | **2003** | **2002** |
| | | | (Thousands) | | |
| Other Income (Expense): | | | | | |
| Income from Unconsolidated Subsidiaries | 3,583 | 3,362 | 805 | 535 | 224 |
| Impairment of Investment in Partnership | | (4,158) | | | (15,167) |
| Interest Income | 10,275 | 6,496 | 1,771 | 2,204 | 2,593 |
| Other Income | 2,825 | 12,744 | 2,908 | 2,427 | 3,184 |
| Interest Expense on Long-Term Debt | (72,629) | (73,244) | (82,989) | (91,381) | (88,646) |
| Other Interest Expense | (5,952) | (9,069) | (6,763) | (11,196) | (15,109) |
| Income from Continuing Operations Before Income Taxes | 214,177 | 246,493 | 248,855 | 305,217 | 183,446 |
| Income Tax Expense | 76,086 | 92,978 | 94,590 | 124,150 | 69,944 |
| Income from Continuing Operations | 138,091 | 153,515 | 154,265 | 181,067 | 113,502 |
| Discontinued Operations: | | | | | |
| Income from Operations, Net of Tax | | 10,199 | 12,321 | 6,769 | 4,180 |
| Gain on Disposal, Net of Tax | | 25,774 | | | |
| Income from Discontinued Operations, Net of Tax | | 35,973 | 12,321 | 6,769 | 4,180 |
| Income Before Cumulative Effect of Changes in Accounting | 138,091 | 189,488 | 166,586 | 187,836 | 117,682 |
| Cumulative Effect of Changes in Accounting | | | | (8,892) | |
| Net Income Available for Common Stock | $ 138,091 | $ 189,488 | $ 166,586 | $ 178,944 | $ 117,682 |
| **Per Common Share Data** | | | | | |
| Basic Earnings from Continuing Operations per Common Share | $ 1.64 | $ 1.84 | $ 1.88 | $ 2.24 | $ 1.42 |
| Diluted Earnings from Continuing Operations per Common Share | $ 1.61 | $ 1.81 | $ 1.86 | $ 2.23 | $ 1.41 |
| Basic Earnings per Common Share(2) | $ 1.64 | $ 2.27 | $ 2.03 | $ 2.21 | $ 1.47 |
| Diluted Earnings per Common Share(2) | $ 1.61 | $ 2.23 | $ 2.01 | $ 2.20 | $ 1.46 |
| Dividends Declared | $ 1.18 | $ 1.14 | $ 1.10 | $ 1.06 | $ 1.03 |
| Dividends Paid | $ 1.17 | $ 1.13 | $ 1.09 | $ 1.05 | $ 1.02 |
| Dividend Rate at Year-End | $ 1.20 | $ 1.16 | $ 1.12 | $ 1.08 | $ 1.04 |
| At September 30: | | | | | |
| **Number of Registered Shareholders** | 17,767 | 18,369 | 19,063 | 19,217 | 20,004 |

Table of Contents

| | Year Ended September 30 | | | | |
|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2003 | 2002 |
| | | | (Thousands) | | |
| **Net Property, Plant and Equipment** | | | | | |
| Utility | $ 1,084,080 | $ 1,064,588 | $ 1,048,428 | $ 1,028,393 | $ 960,015 |
| Pipeline and Storage | 674,175 | 680,574 | 696,487 | 705,927 | 487,793 |
| Exploration and Production | 1,002,265 | 974,806 | 923,730 | 925,833 | 1,072,200 |
| Energy Marketing | 59 | 97 | 80 | 171 | 125 |
| Timber | 90,939 | 94,826 | 82,838 | 87,600 | 110,624 |
| All Other | 17,394 | 18,098 | 21,172 | 22,042 | 6,797 |
| Corporate(3) | 8,814 | 6,311 | 234,029 | 221,082 | 207,191 |
| Total Net Plant | $ 2,877,726 | $ 2,839,300 | $ 3,006,764 | $ 2,991,048 | $ 2,844,745 |
| **Total Assets** | $ 3,734,331 | $ 3,725,282 | $ 3,717,603 | $ 3,725,414 | $ 3,429,163 |
| **Capitalization** | | | | | |
| Comprehensive Shareholders Equity | $ 1,443,562 | $ 1,229,583 | $ 1,253,701 | $ 1,137,390 | $ 1,006,858 |
| Long-Term Debt, Net of Current Portion | 1,095,675 | 1,119,012 | 1,133,317 | 1,147,779 | 1,145,341 |
| Total Capitalization | $ 2,539,237 | $ 2,348,595 | $ 2,387,018 | $ 2,285,169 | $ 2,152,199 |

(1) Certain prior year amounts have been reclassified to conform with current year presentation.

(2) Includes discontinued operations and cumulative effect of changes in accounting.

(3) Includes net plant of the former international segment as follows: $27 for 2006, $20 for 2005, $227,905 for 2004, $219,199 for 2003, and $207,191 for 2002.

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

**OVERVIEW**

The Company is a diversified energy company consisting of five reportable business segments. Refer to Item I, 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.) 2006 and 2007 funding to the Company s defined benefit retirement plan and post-retirement benefit plan, 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.

The event that had the most significant earnings impact in 2006, and the main reason for the significant earnings decrease over 2005, was the Exploration and Production segment recording after-tax impairment charges totaling $68.6 million related to its Canadian oil and gas assets during 2006 under the full cost method of accounting, which is discussed below under Critical Accounting Estimates. In addition, the Company s earnings for 2006 as compared to 2005 are impacted by the Company s 2005 sale of its entire 85.16% interest in U.E., a district heating and electric generation business in the Czech Republic. This sale resulted in a $25.8 million gain in 2005, net of tax. As a result of the decision to sell its majority interest in U.E., the Company began presenting the Czech Republic operations as discontinued operations in June 2005. With this change in presentation, the Company discontinued all reporting for an International segment. Any remaining international activity has been included in corporate operations for all periods presented below. The Company s earnings are discussed further in the Results of Operations section that follows.

From a capital resources and liquidity perspective, the Company spent $294.2 million on capital expenditures during 2006, with approximately 71% being spent in the Exploration and Production segment. This is in line with the Company s expectations. In November 2006, the Company announced that it had selected EOG Resources, Inc. (EOG) to jointly explore approximately 770,000 acres of the Company s mineral holdings and 130,000 acres of EOG s mineral holdings in Pennsylvania and New York. EOG will be the operator and the primary exploration targets are the Devonian black shales, which have similar characteristics to the prolific Barnett Shale that is actively producing natural gas in the Fort Worth Basin. Exploratory drilling is expected to begin in 2007; however, the Company does not share in the initial exploratory costs and no capital expenditures have been forecasted for 2007 related to this joint venture.* Earliest production estimates have production starting no sooner than 2008.*

The Company is still pursuing its Empire Connector project to expand its natural gas pipeline operations. In July 2006, Empire revised the planned in-service date for the Empire Connector to extend beyond November 2007, as originally reported. The new targeted in-service date is November 2008, or sooner if feasible.* On July 20, 2006, FERC issued a Preliminary Determination regarding the rate and non-environmental aspects of Empire s application for FERC approval. Empire then made a compliance filing on September 18, 2006 regarding certain non-environmental issues, which is discussed further in the Capital Resources and Liquidity section that follows. On October 13, 2006, FERC subsequently issued a final environmental impact statement on the Empire Connector project and the other related downstream projects, indicating that FERC has not identified any environmental reasons why those projects could not be built. There are no other significant changes in the status of the project and the Company continues to await final FERC approval to build and operate the project.

The Company also began repurchasing outstanding shares of common stock during the quarter ended March 31, 2006 under a share repurchase program authorized by the Company s Board of Directors. The program authorizes the Company to repurchase up to an aggregate amount of 8 million shares. Through September 30, 2006, the Company had repurchased 2,526,550 shares. These matters are discussed further in the Capital Resources and Liquidity section that follows.

From a rate and regulatory matters perspective, management is concerned with declining usage per customer in the Utility segment. It has been one of the items leading to the filing of rate cases in New York and Pennsylvania. In Pennsylvania, the Company filed a rate case in June 2006 that included a revenue decoupling mechanism, or a conservation tracker. A settlement for this rate case was reached in October 2006, and while the revenue decoupling mechanism was withdrawn in order to achieve the settlement, the PaPUC instituted a generic proceeding to look at rate mechanisms such as revenue decoupling across the state. In New York, there is currently a proceeding going on to examine revenue decoupling mechanisms.

Lastly, on April 7, 2006, the NYPSC, PaPUC and Pennsylvania Office of Consumer Advocate filed a complaint and motion for summary disposition against Supply Corporation with the FERC. The complainants alleged that Supply Corporation s rates were unjust and unreasonable, and that Supply Corporation was permitted to retain more gas from shippers than it needed for fuel and loss. It also asked FERC to determine whether Supply Corporation had the authority to make sales of gas retained from shippers (which are referred to under Results of Operations as unbundled pipeline sales ). On September 26, 2006, the active parties reached a settlement in principle. On November 17, 2006, Supply Corporation filed a motion asking FERC to approve an uncontested settlement of the proceeding. The proposed settlement would be implemented when and if FERC approves the settlement, but if approved would be effective as of December 1, 2006. This matter, including the primary elements of the settlement, is discussed more fully in the Rate and Regulatory 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 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). Unevaluated properties are excluded from the depletion calculation until they are evaluated. Once they are evaluated, costs associated with these properties are transferred to the pool of costs being depleted.

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 is performed on a country-by-country basis and determines a limit, or ceiling, to 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 revenues 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 taxes. 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 or subtractions to 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. Further decreases in the price of natural gas, absent the addition of new reserves, could result in future impairments.*

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

*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, options and futures contracts. The Company, in its Pipeline and Storage segment, uses an interest rate collar to limit interest rate fluctuations on certain variable rate debt. In accordance with the provisions of SFAS 133, the Company accounts for these instruments as effective cash flow hedges or fair value hedges. As such, 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. As discussed below, the Company was required to discontinue hedge accounting for a portion of its derivative financial instruments, resulting in a charge to earnings in 2005.

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The fair value of the non exchange-traded derivative financial instruments are based on valuations determined by the 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 discount rate used by the Company is equal to the Moody s Aa Long-Term Corporate Bond index, rounded to the nearest 25 basis points. The duration of the securities underlying that index (approximately 13 years) reasonably matches the expected timing of anticipated future benefit payments (approximately 12 years). 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 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 96% and 97%, 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, 2006 and September 30, 2005.

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 post-retirement benefit plans and could impact the Company s equity. For example, the discount rate used to determine benefit obligations was changed from 5.0% in 2005 to 6.25% in 2006. The change in the discount rate reduced the pension plan projected benefit obligation by $113.1 million and the accumulated post-retirement benefit obligation by $77.5 million. As a result of the discount rate change, the Company no longer had to record a minimum pension liability adjustment at September 30, 2006, resulting in an increase to other comprehensive income of $107.8 million, as shown in the Consolidated Statement of Comprehensive Income. 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 obligations and the accumulated post-retirement benefit obligation for the Post-Retirement Plan. For 2006, actual versus expected return on plan assets resulted in an increase to the funded status of the Retirement Plan and the Post-Retirement Plan of $18.7 million and $12.5 million, respectively. The actual versus expected benefit payments for 2006 caused a decrease of $1.0 million and $0.3 million to the projected benefit obligation and accumulated post-retirement benefit obligation, respectively. In calculating the projected benefit obligation for the Retirement Plan and the accumulated post-retirement obligation for the Post-Retirement Plan, the actuary takes into account the average remaining service life of active participants. The average remaining service life of active participants in the Retirement Plan is 10 years. The average remaining service life of active participants in the Post-Retirement Plan is 9 years. For further discussion of the Company s pension and other post-retirement benefits, refer to Other Matters in this Item 7 and to Item 8 at Note G Retirement Plan and Other Post Retirement Benefits.

## RESULTS OF OPERATIONS

### EARNINGS

### 2006 Compared with 2005

The Company s earnings were $138.1 million in 2006 compared with earnings of $189.5 million in 2005. As previously discussed, the Company presented its Czech Republic operations as discontinued operations in conjunction with the sale of U.E. The Company s earnings from continuing operations were $138.1 million in 2006 compared with $153.5 million in 2005. The Company s earnings from discontinued operations were zero in 2006 compared with $36.0 million in 2005. The decrease in earnings from continuing operations of $15.4 million is primarily the result of lower earnings in the Exploration and Production and Pipeline and Storage segments offset somewhat by higher earnings in the Utility segment, Energy Marketing segment, Timber segment, and All Other category and a lower loss in the Corporate category, as shown in the table below. The decrease in earnings from discontinued operations reflects the non-recurrence of the gain on the sale of U.E. recognized in 2005. In the discussion that follows, note that all amounts used in the earnings discussions are after tax amounts. Earnings from continuing operations and discontinued operations were impacted by several events in 2006 and 2005, including:

***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 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 a regulatory mechanism calculation.

***2005 Events***

A $25.8 million gain on the sale of U.E., which was completed in July 2005. This amount is included in earnings from discontinued operations;

A $2.6 million gain in the Pipeline and Storage segment associated with a FERC approved sale of base gas;

A $3.9 million gain in the Pipeline and Storage segment associated with insurance proceeds received in prior years for which a contingency was resolved during 2005;

A $3.3 million loss related to certain derivative financial instruments that no longer qualified as effective hedges;

A $2.7 million impairment in the value of the Company s 50% investment in ESNE (recorded in the All Other category), a limited liability company that owns an 80-megawatt, combined cycle, natural gas-fired power plant in the town of North East, Pennsylvania; and

A $1.8 million impairment of a gas-powered turbine in the All Other category that the Company had planned to use in the development of a co-generation plant.

**2005 Compared with 2004**

The Company s earnings were $189.5 million in 2005 compared with earnings of $166.6 million in 2004. As previously discussed, the Company has presented its Czech Republic operations as discontinued operations. The Company s earnings from continuing operations were $153.5 million in 2005 compared with $154.3 million in 2004. The Company s earnings from discontinued operations were $36.0 million in 2005 compared with $12.3 million in 2004. Earnings from continuing operations did not change significantly as higher earnings in the Pipeline and Storage segment were largely offset by lower earnings in the Utility and Exploration and Production segments and a higher loss in the All Other category. The increase in earnings from discontinued operations resulted from the gain on the sale of U.E. in 2005. Earnings from continuing operations and discontinued operations were impacted by the 2005 events discussed above and the following 2004 events:

***2004 Events***

A $5.2 million reduction to deferred income tax expense resulting from a change in the statutory income tax rate in the Czech Republic. This amount is included in earnings from discontinued operations;

Settlement of a pension obligation which resulted in the recording of additional expense amounting to $6.4 million, allocated among the segments as follows: $2.2 million to the Utility segment ($1.2 million in the New York jurisdiction and $1.0 million in the Pennsylvania jurisdiction), $2.0 million to the Pipeline and Storage segment ($1.8 million to Supply Corporation and $0.2 million to Empire State Pipeline), $0.9 million to the Exploration and Production segment, $0.3 million to the Energy Marketing segment and $1.0 million to the Corporate and All Other categories;

Table of Contents

An adjustment to the 2003 sale of the Company s Southeast Saskatchewan oil and gas properties in the Exploration and Production segment which increased 2004 earnings by $4.6 million; and

An adjustment to the Company s 2003 sale of its timber properties in the Timber segment, which reduced 2004 earnings by $0.8 million.

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 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Thousands) | |
| Utility | $ 49,815 | $ 39,197 | $ 46,718 |
| Pipeline and Storage | 55,633 | 60,454 | 47,726 |
| Exploration and Production | 20,971 | 50,659 | 54,344 |
| Energy Marketing | 5,798 | 5,077 | 5,535 |
| Timber | 5,704 | 5,032 | 5,637 |
| Total Reportable Segments | 137,921 | 160,419 | 159,960 |
| All Other | 359 | (2,616) | 1,530 |
| Corporate(1) | (189) | (4,288) | (7,225) |
| Total Earnings from Continuing Operations | $ 138,091 | $ 153,515 | $ 154,265 |
| Earnings from Discontinued Operations | | 35,973 | 12,321 |
| Total Consolidated | $ 138,091 | $ 189,488 | $ 166,586 |

(1) Includes earnings from the former International segment s activity other than the activity from the Czech Republic operations included in Earnings from Discontinued Operations.

**UTILITY**

**Revenues**

**Utility Operating Revenues**

| Year Ended September 30 | | |
|---|---|---|
| 2006 | 2005 | 2004 |
| | (Thousands) | |

| | | | |
|---|---|---|---|
| Retail Revenues: | | | |
| Residential | $ 993,928 | $ 868,292 | $ 808,740 |
| Commercial | 166,779 | 145,393 | 137,092 |
| Industrial | 13,484 | 13,998 | 17,454 |
| | 1,174,191 | 1,027,683 | 963,286 |
| Off-System Sales | | | 106,841 |
| Transportation | 92,569 | 83,669 | 80,563 |
| Other | 14,003 | 5,715 | 1,951 |
| | $ 1,280,763 | $ 1,117,067 | $ 1,152,641 |

Table of Contents

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Retail Sales: | | | |
| Residential | 59,443 | 66,903 | 70,109 |
| Commercial | 10,681 | 11,984 | 12,752 |
| Industrial | 985 | 1,387 | 2,261 |
| | 71,109 | 80,274 | 85,122 |
| Off-System Sales | | | 16,839 |
| Transportation | 57,950 | 59,770 | 60,565 |
| | 129,059 | 140,044 | 162,526 |

**Degree Days**

| | | | | Percent (Warmer) Colder Than | |
|---|---|---|---|---|---|
| **Year Ended September 30** | | **Normal** | **Actual** | **Normal** | **Prior Year** |
| 2006: | Buffalo | 6,692 | 5,968 | (10.8)% | (9.4)% |
| | Erie | 6,243 | 5,688 | (8.9)% | (8.9)% |
| 2005: | Buffalo | 6,692 | 6,587 | (1.6)% | 0.2% |
| | Erie | 6,243 | 6,247 | 0.1% | 2.6% |
| 2004: | Buffalo | 6,729 | 6,572 | (2.3)% | (7.9)% |
| | Erie | 6,277 | 6,086 | (3.0)% | (10.1)% |

**2006 Compared with 2005**

Operating revenues for the Utility segment increased $163.7 million in 2006 compared with 2005. This increase largely resulted from a $146.5 million increase in retail gas sales revenues. Transportation revenues and other revenues also increased by $8.9 million and $8.3 million, respectively.

The increase in retail gas sales revenues for the Utility segment was largely a function of the recovery of higher gas costs (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. Warmer weather, as shown in the table above, and greater conservation by customers due to higher natural gas commodity prices, were the principal reasons for the decrease in retail sales volumes.

The increase in transportation revenues was primarily due to a $5.9 million increase in the New York jurisdiction s calculation of the symmetrical sharing component of the gas adjustment rate. The symmetrical sharing component is a mechanism included in Distribution Corporation s New York rate settlement that shares with customers 90% of the difference between actual revenues received from large volume customers and the level of revenues that were projected to be received during the rate year. Of the $5.9 million increase, $3.9 million was due to an out-of-period adjustment recorded in fiscal year 2006 when it was determined that certain credits that had been included in the calculation should have been removed during the implementation of a previous rate case. The adjustment related to fiscal years 2002 through 2005.

The impact of the August 2005 New York rate case settlement was to increase operating revenues by $19.1 million (of which $12.4 million was an increase to other operating revenues). This increase consisted of a base rate increase, the implementation of a merchant function charge, the elimination of certain bill credits, and the elimination of the gross receipts tax surcharge. The settlement also allowed Distribution Corporation to continue 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 2005, Distribution Corporation utilized

Table of Contents

$7.8 million of the cost mitigation reserve, which increased other operating revenues, to recover previous under-collections of pension and post-retirement expenses. The impact of that increase in other operating revenues was offset by an equal amount of operation and maintenance expense (thus there was no earnings impact). Distribution Corporation did not record any entries involving the cost mitigation reserve in 2006. Other operating revenues was also impacted by two out-of-period regulatory adjustments recorded during 2005. The first adjustment related to the final settlement with the Staff of the NYPSC of the earnings sharing liability for the 2001 to 2003 time period. As a result of that settlement, the New York rate jurisdiction recorded additional earnings sharing expense (as an offset to other operating revenues) of $0.9 million. The second adjustment related to a regulatory liability recorded for previous over-collections of New York State gross receipts tax. In preparing for the implementation of the settlement agreement in New York, the Company determined that it needed to adjust that regulatory liability by $3.1 million (of which $1.0 million was recorded as a reduction of other operating revenues and $2.1 million was recorded as additional interest expense) related to fiscal years 2004 and prior. These adjustments did not recur in 2006.

In the Pennsylvania jurisdiction, the impact of the base rate increase, which became effective in mid-April 2005, was to increase operating revenues by $7.5 million. This increase is included within both retail and transportation revenues in the table above.

**2005 Compared with 2004**

Operating revenues for the Utility segment decreased $35.6 million in 2005 compared with 2004. This resulted primarily from the absence of off-system sales revenues of $106.8 million, offset by an increase of $64.4 million in retail revenues. Effective September 22, 2004, Distribution Corporation stopped making off-system sales as a result of the FERC s Order 2004, Standards of Conduct for Transmission Providers. However, due to profit sharing with retail customers, the margins resulting from off-system sales have been minimal and there was not a material impact to margins in 2005. The increase in retail revenues was primarily the result of the recovery of higher gas costs (gas costs are recovered dollar for dollar in revenues), colder weather in the Pennsylvania jurisdiction and the impact of base rate increases in both New York and Pennsylvania. The recovery of higher gas costs resulted from a much higher cost of purchased gas. See further discussion of purchased gas below under the heading Purchased Gas. Lower retail sales volumes, due primarily to lower customer usage per account, partially offset the increase in retail revenues associated with the recovery of higher gas costs and the base rate increases. Also, retail industrial sales revenue declined due to fuel switching and production declines of certain large volume industrial customers as a result of a general economic downturn in the Utility segment s service territory.

The increase in other operating revenues of $3.8 million is largely related to amounts recorded pursuant to rate settlements with 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, 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 $12.07 per Mcf in 2006, an increase of 31% from the average cost of $9.19 per Mcf in 2005. The average cost of purchased gas in 2005 was 26% higher than the average cost of $7.30 per Mcf in 2004. Additional discussion of the Utility segment s gas purchases appears under the heading Sources and Availability of Raw Materials in Item 1.

Table of Contents

## Earnings

### 2006 Compared with 2005

The Utility segment s earnings in 2006 were $49.8 million, an increase of $10.6 million when compared with earnings of $39.2 million in 2005.

In the New York jurisdiction, earnings increased by $9.2 million, primarily due to the positive impact of the rate case settlement in this jurisdiction that became effective August 2005 ($13.7 million). In addition, the increase in the New York jurisdiction s calculation of the symmetrical sharing component of the gas adjustment rate, including the out-of-period adjustment discussed above, contributed $3.9 million to earnings. Two out-of-period regulatory adjustments recorded during fiscal year 2005 that did not recur during 2006, as discussed above, also contributed an additional $2.6 million to earnings. The first adjustment, related to the final settlement with the Staff of the NYPSC of the earnings sharing liability for the fiscal 2001 through 2003 time period, increased earnings in fiscal 2006 by $0.6 million. The second adjustment, related to a regulatory liability recorded for previous over-collections of New York State gross receipts tax, increased earnings in fiscal 2006 by $2.0 million. The increase in earnings due to the New York rate case settlement, the symmetrical sharing component of the gas adjustment rate, and the two out-of-period regulatory adjustments recorded in 2005, was partially offset by a decline in margin associated with lower weather-normalized usage by customers ($2.3 million), higher operation expenses ($2.5 million), higher interest expense ($2.7 million), and a higher effective income tax rate ($3.2 million). The higher effective income tax rate is due to positive tax adjustments recorded in 2005 that did not recur in 2006. The increase in operation expenses consisted primarily of higher pension expense offset by lower bad debt expense.

In the Pennsylvania jurisdiction, earnings increased by $1.4 million, due to the positive impact of the rate case settlement in this jurisdiction that became effective April 2005 ($4.9 million), and lower operation expenses ($1.8 million). The decrease in operation expenses consisted primarily of lower bad debt expense offset partially by higher pension expense. These increases to earnings were partially offset by the impact of warmer than normal weather in Pennsylvania ($3.0 million), lower weather-normalized usage by customer ($0.6 million), higher interest expense ($0.8 million), and a higher effective tax rate ($1.3 million).

The decrease in bad debt expense reflects the fact that in the fourth quarter of 2005, the New York and Pennsylvania jurisdictions increased the allowance for uncollectible accounts to reflect the increase in final billed account balances and the increased aging of outstanding active receivables heading into the heating season. A similar adjustment was not required in 2006.

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 2006, the WNC preserved earnings of approximately $6.2 million because it was warmer than normal in the New York service territory. In 2005, the WNC did not have a significant impact on earnings.

### 2005 Compared with 2004

The Utility segment s earnings in 2005 were $39.2 million, a decrease of $7.5 million when compared with earnings of $46.7 million in 2004. The major factors driving this decrease were lower weather-normalized usage per customer account in both the New York and Pennsylvania jurisdictions ($8.2 million) and an increase in bad debt expenses of $6.7 million. The increase in bad debt expenses is attributable to the increase in the allowance for uncollectible accounts to reflect the increase in final billed balances, as well as the increased age of outstanding receivables heading into the heating season. These negative factors were partially offset by the impact of base rate increases in both New

York and Pennsylvania ($3.9 million) and the recording of accrued interest on a pension related asset in accordance with the New York rate case settlement agreement ($2.4 million), as well as the impact of colder than normal weather in Pennsylvania ($1.0 million). The earnings impact of the two out-of-period regulatory adjustments discussed above was largely offset by lower interest expense on borrowings due to lower debt balances.

In 2005, the WNC did not have a significant impact on earnings. For 2004, the WNC preserved earnings of approximately $1.0 million because it was warmer than normal in the New York service territory.

**PIPELINE AND STORAGE**

**Revenues**

**Pipeline and Storage Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 (Thousands) | 2004 |
| Firm Transportation | $ 118,551 | $ 117,146 | $ 120,443 |
| Interruptible Transportation | 4,858 | 4,413 | 3,084 |
| | 123,409 | 121,559 | 123,527 |
| Firm Storage Service | 66,718 | 65,320 | 63,962 |
| Interruptible Storage Service | 39 | 267 | 20 |
| | 66,757 | 65,587 | 63,982 |
| Other | 24,186 | 28,713 | 22,198 |
| | $ 214,352 | $ 215,859 | $ 209,707 |

**Pipeline and Storage Throughput (MMcf)**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Firm Transportation | 363,379 | 357,585 | 338,991 |
| Interruptible Transportation | 11,609 | 14,794 | 12,692 |
| | 374,988 | 372,379 | 351,683 |

**2006 Compared with 2005**

Operating revenues for the Pipeline and Storage segment decreased $1.5 million in 2006 as compared with 2005. This decrease consisted of a $4.5 million decrease in other revenues offset by a $1.8 million increase in firm and interruptible transportation revenues and a $1.2 million increase in firm and interruptible storage service revenues. The decrease in other revenues is primarily due to a $2.6 million decrease in revenues from unbundled pipeline sales, due to lower natural gas prices, as well as a $0.7 million decrease in cashout revenues. Cashout revenues are completely offset by purchased gas expense. The increase in firm and interruptible transportation revenues is due to additional contracts with customers and the renewal of contracts at higher rates, both of which reflect the increased demand for transportation services due to market conditions resulting from the effects of hurricane damage to production and pipeline infrastructure in the Gulf of Mexico during the fall of 2005. While Supply Corporation s transportation volumes increased 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. The increase in storage revenues reflects the renewal of storage contracts at higher rates.

**2005 Compared with 2004**

Operating revenues for the Pipeline and Storage segment increased $6.2 million in 2005 as compared with 2004. This increase is primarily attributable to higher revenues from unbundled pipeline sales of $5.5 million included in other revenues in the table above, due to higher natural gas prices. Higher cashout revenues of $1.1 million, reported as part of other revenues in the table above, also contributed to the increase. Cashout revenues are completely offset by purchased gas expense. In addition, interruptible transportation revenues increased by $1.3 million, primarily due to an increase in Supply Corporation s gathering revenues, and firm storage revenues increased $1.4 million, primarily due to higher rate agreements contracted with Supply Corporation customers. Offsetting these increases, the decrease in firm transportation revenues of $3.3 million reflects the cancellation of contracts with Supply Corporation by certain large usage non-affiliated customers ($2.6 million) and the Utility segment s cancellation of a portion of its firm transportation with Supply Corporation in April 2005 ($0.6 million). In addition, firm transportation revenues decreased by $1.0 million because Supply Corporation no longer charges customers a surcharge for its membership to the Gas Research Institute (GRI). The decrease in revenues resulting from cancellation of the GRI surcharge was completely offset by lower operation expense. While Supply Corporation s transportation volumes increased 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. Offsetting the decreases in Supply Corporation s firm transportation revenues was a $1.0 million increase in Empire s firm transportation revenues, primarily due to an increase in transportation volumes.

**Earnings**

**2006 Compared with 2005**

The Pipeline and Storage segment s earnings in 2006 were $55.6 million, a decrease of $4.9 million when compared with earnings of $60.5 million in 2005. The decrease reflects the non-recurrence of two events, a $2.6 million gain on a FERC approved sale of base gas in 2005 and a $3.9 million gain associated with insurance proceeds received in prior years for which a contingency was resolved in 2005. Both of these items were recorded in Other Income. It also reflects the earnings impact associated with lower revenues from unbundled pipeline sales ($1.7 million) and higher operation expenses ($0.6 million). These earnings decreases were offset by the positive earnings impact of higher transportation and storage revenues ($2.0 million), lower depreciation due to the non-recurrence of a write-down of the Company s former corporate office in 2005 ($0.9 million), and the earnings benefit associated with a lower effective tax rate ($1.7 million).

**2005 Compared with 2004**

The Pipeline and Storage segment s earnings in 2005 were $60.5 million, an increase of $12.8 million when compared with earnings of $47.7 million in 2004. Contributing to the increase was a gain of $3.9 million associated with the insurance proceeds received in prior years for which a contingency was resolved during 2005. The other main factors contributing to the increase were higher revenues from unbundled pipeline sales ($3.6 million), lower interest expense ($2.4 million), $2.0 million of expense that did not recur in 2005 associated with the settlement of a pension obligation recognized in 2004, as well as a $2.6 million gain on the FERC approved sale of base gas in March, 2005. An increase in the reserve for preliminary project costs associated with the Empire Connector project ($1.8 million) partially offset these increases.

**EXPLORATION AND PRODUCTION**

**Revenues**

**Exploration and Production Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 (Thousands) | 2004 |
| Gas (after Hedging) | $ 184,268 | $ 181,713 | $ 167,127 |

| | | | |
|---|---|---|---|
| Oil (after Hedging) | 148,293 | 107,801 | 119,564 |
| Gas Processing Plant | 42,252 | 36,350 | 28,614 |
| Other | 3,771 | (2,733) | 1,815 |
| Intrasegment Elimination(1) | (31,704) | (29,706) | (23,422) |
| | $ 346,880 | $ 293,425 | $ 293,698 |

Table of Contents

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

**Production Volumes**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| **Gas Production** *(MMcf)* | | | |
| Gulf Coast | 9,110 | 12,468 | 17,596 |
| West Coast | 3,880 | 4,052 | 4,057 |
| Appalachia | 5,108 | 4,650 | 5,132 |
| Canada | 7,673 | 8,009 | 6,228 |
| | 25,771 | 29,179 | 33,013 |
| **Oil Production** *(Mbbl)* | | | |
| Gulf Coast | 685 | 989 | 1,534 |
| West Coast | 2,582 | 2,544 | 2,650 |
| Appalachia | 69 | 36 | 20 |
| Canada | 272 | 300 | 324 |
| | 3,608 | 3,869 | 4,528 |

**Average Prices**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| **Average Gas Price/Mcf** | | | |
| Gulf Coast | $ 8.01 | $ 7.05 | $ 5.61 |
| West Coast | $ 7.93 | $ 6.85 | $ 5.54 |
| Appalachia | $ 9.53 | $ 7.60 | $ 5.91 |
| Canada | $ 7.14 | $ 6.15 | $ 4.87 |
| Weighted Average | $ 8.04 | $ 6.86 | $ 5.51 |
| Weighted Average After Hedging(1) | $ 7.15 | $ 6.23 | $ 5.06 |
| **Average Oil Price/Barrel (bbl)** | | | |
| Gulf Coast | $ 64.10 | $ 49.78 | $ 35.31 |
| West Coast(2) | $ 56.80 | $ 42.91 | $ 31.89 |
| Appalachia | $ 65.28 | $ 48.28 | $ 31.30 |
| Canada | $ 51.40 | $ 42.97 | $ 30.94 |
| Weighted Average | $ 57.94 | $ 44.72 | $ 32.98 |
| Weighted Average After Hedging(1) | $ 41.10 | $ 27.86 | $ 26.40 |

(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.

**2006 Compared with 2005**

Operating revenues for the Exploration and Production segment increased $53.5 million in 2006 as compared with 2005. Oil production revenue after hedging increased $40.5 million due primarily to higher weighted average prices after hedging ($13.24 per barrel). This increase was offset slightly by a decrease in production (261,000 barrels). Gas production revenue after hedging increased $2.6 million. Increases in the weighted average price of gas after hedging ($0.92 per Mcf) more than offset an overall decrease in gas production (3,408 MMcf). The decrease in gas production occurred primarily in the Gulf Coast (a 3,358 MMcf decline), which is partly attributable to last fall s hurricane damage and partly attributable to the expected decline rates for the Company s production in the region. Other revenues increased $6.5 million largely due to the non-recurrence of a $5.1 million mark-to-market adjustment, recorded in 2005, for losses on certain derivative financial instruments that no longer qualified as effective hedges due to the anticipated delays in oil and gas production volumes caused by Hurricane Rita.

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.

**2005 Compared with 2004**

Operating revenues for the Exploration and Production segment decreased $0.3 million in 2005 as compared with 2004. Oil production revenue after hedging decreased $11.8 million due to a 659 Mbbl decline in production offset partly by higher weighted average prices after hedging ($1.46 per barrel). Most of the decrease in oil production occurred in the Gulf Coast Region (a 545 Mbbl decrease). Gas production revenue after hedging increased $14.6 million. Increases in the weighted average price of gas after hedging ($1.17 per Mcf) more than offset an overall decrease in gas production (3,834 MMcf). Most of the decrease in gas production occurred in the Gulf Coast (a 5,128 MMcf decline). The decreases in Gulf Coast oil and gas production are consistent with the expected decline rates in the region. This decrease in Gulf Coast gas production was partially offset by a 1,781 MMcf increase in Canadian gas production. The increase in Canadian gas production is attributable to the Sukunka 60-E well, in which the Company has a 20% working interest. Other revenues decreased $4.5 million largely due to a $5.1 million mark-to-market adjustment for losses on certain derivative financial instruments that no longer qualified as effective hedges due to the anticipated delays in oil and gas production volumes caused by Hurricane Rita. These volumes were originally forecast to be produced in the first quarter of 2006.

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**

**2006 Compared with 2005**

The Exploration and Production segment s earnings in 2006 were $21.0 million, a decrease of $29.7 million when compared with earnings of $50.7 million in 2005. The decrease is primarily the result of the impairment charges of $68.6 million on this segment s Canadian oil and gas producing properties. Also, lower oil and gas production decreased earnings by $18.5 million. Further contributing to the decrease were higher lease operating expenses ($3.2 million), higher general and administrative and other operating costs ($2.0 million) and higher depletion expense ($2.5 million). The increase in lease operating expenses was primarily in the West Coast region due to higher steaming costs associated with heavy crude oil production in the California Midway-Sunset and North Lost Hills fields. The higher steaming costs are due to an increase in the price for natural gas purchased in the field and used in the steaming operations, primarily in the second quarter of fiscal 2006, compared to the second quarter of fiscal 2005. Beginning in April 2006, a scrubber facility in the Midway-Sunset field was in full operation and is burning waste gas rather than purchased gas to generate the steam for its thermal recovery project. It is anticipated that the scrubber facility will reduce steaming costs in the future.* The increase in depletion expense was mainly due to higher finding and development costs in the Canadian region, coupled with a 10.5 Bcfe downward revision of the proved reserve estimate (resulting in an increase to the per unit depletion rate) in this region in 2006. Partially offsetting these decreases, higher oil and gas prices, as discussed above, contributed $46.5 million to earnings. Also, the non-recurrence of the 2005 mark-to-market adjustment discussed under Revenues above, contributed $3.3 million to earnings and strong cash flow provided higher interest income ($2.6 million). In the second quarter of 2006, a $5.1 million benefit to earnings was realized for an adjustment to a deferred income tax balance. Under GAAP, a company may recognize the benefit of certain expected future income tax deductions as a deferred tax asset only if it anticipates sufficient future taxable income to utilize those deductions. As a result of the rise in commodity prices, the Company increased its forecast of future taxable income in the Exploration and Production segment s Canadian division and, as a result, recorded a deferred tax asset for certain drilling costs that it now expects to deduct on future income tax returns. In the third quarter of 2006, a $6.1 million benefit to earnings related to income taxes was recognized. The Company reversed a valuation allowance ($2.9 million) associated with the capital loss carryforward that resulted from the 2003 sale of certain of Seneca s oil properties, and also recognized a tax benefit of $3.2 million related to the favorable resolution of certain open tax issues.

**2005 Compared with 2004**

The Exploration and Production segment s earnings in 2005 were $50.7 million, a decrease of $3.6 million when compared with earnings of $54.3 million in 2004. Lower oil and gas production, as discussed above, decreased earnings by $23.9 million. Also, in 2004, the Company recorded an adjustment to the sale of its Southeast Saskatchewan properties that increased 2004 earnings by $4.6 million. In 2005, the Company recorded a mark-to-market adjustment, as discussed above under Revenues , that decreased 2005 earnings by $3.3 million. Higher lease operating and depletion expenses also decreased 2005 earnings by $2.1 million and $0.6 million, respectively. The increase in lease operating expenses resulted mainly from increased Canadian production and higher steaming costs associated with heavy crude oil production in the West Coast Region. Depletion expense increased despite a drop in production mostly due to an increase in the per unit depletion rate, which was largely the result of the higher finding and development costs experienced by Seneca in 2005. All of these factors, which collectively resulted in a $34.5 million decrease in 2005 earnings, were partially offset by higher oil and gas prices, as discussed above, that contributed $25.9 million to earnings. Also, 2005 earnings benefited from higher interest income ($1.8 million) and lower interest expense ($1.2 million). The fluctuations in interest income and interest expense reflect the fact that the Exploration and Production segment has been operating solely within its own cash flow from operations. Short-term borrowings have been eliminated and excess cash has been invested, resulting in higher interest income. This excess cash will be used to fund operations and future capital expenditures.* Lower general and administrative expenses, largely due to lower legal costs, also increased 2005 earnings by $1.0 million.

**ENERGY MARKETING**

**Revenues**

**Energy Marketing Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Thousands) | |
| Natural Gas (after Hedging) | $ 496,769 | $ 329,560 | $ 283,747 |
| Other | 300 | 154 | 602 |
| | $ 497,069 | $ 329,714 | $ 284,349 |

**Energy Marketing Volumes**

| | Year Ended September 30 | | |
| --- | --- | --- | --- |
| | 2006 | 2005 | 2004 |
| Natural Gas (MMcf) | 45,270 | 40,683 | 41,651 |

**2006 Compared with 2005**

Operating revenues for the Energy Marketing segment increased $167.4 million in 2006 as compared with 2005. The increase primarily reflects higher natural gas commodity prices that were recovered through revenues, and, to a lesser extent, an increase in throughput. The increase in throughput was due to the addition of certain large commercial and industrial customers, which more than offset any decrease in throughput due to warmer weather and greater conservation by customers due to higher natural gas prices.

**2005 Compared with 2004**

Operating revenues for the Energy Marketing segment increased $45.4 million in 2005 as compared with 2004. The increase primarily reflects an increase in the price of natural gas. Volumes were down compared to the prior year due to the loss of certain lower margin wholesale customers.

**Earnings**

**2006 Compared with 2005**

The Energy Marketing segment s earnings in 2006 were $5.8 million, an increase of $0.7 million when compared with earnings of $5.1 million in 2005. Despite warmer weather and greater conservation by customers, gross margin increased due to a number of factors, including higher volumes and the marketing flexibility associated with stored gas. The Energy Marketing segment s contracts for significant storage and transportation volumes provided operational flexibility resulting in increased sales throughput and earnings. The increase in gross margin more than offset an increase in operation expense.

**2005 Compared with 2004**

The Energy Marketing segment s earnings in 2005 were $5.1 million, a decrease of $0.4 million when compared with earnings of $5.5 million in 2004. The decrease primarily reflects lower margins caused by a reduction in the benefit of storage gas and, to a lesser extent, lower throughput.

**TIMBER**

**Revenues**

**Timber Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Thousands) | |
| Log Sales | $ 23,077 | $ 22,478 | $ 21,790 |
| Green Lumber Sales | 7,123 | 7,296 | 5,923 |
| Kiln Dry Lumber Sales | 32,809 | 29,651 | 27,416 |
| Other | 2,020 | 1,861 | 841 |
| | $ 65,029 | $ 61,286 | $ 55,970 |

**Timber Board Feet**

**Year Ended September 30**

| | 2006 | 2005 (Thousands) | 2004 |
|---|---|---|---|
| Log Sales | 9,527 | 7,601 | 6,848 |
| Green Lumber Sales | 10,454 | 10,489 | 9,552 |
| Kiln Dry Lumber Sales | 16,862 | 15,491 | 15,020 |
| | 36,843 | 33,581 | 31,420 |

**2006 Compared with 2005**

Operating revenues for the Timber segment increased $3.7 million in 2006 as compared with 2005. This increase can be chiefly attributed to an increase in kiln dry lumber sales of $3.2 million principally due to an increase in kiln dry cherry lumber sales volumes of 2.0 million board feet. Other kiln dry lumber sales volumes decreased by 0.6 million board feet, but there was little impact to revenues. The addition of two new kilns in February 2005 allowed for greater processing capacity in 2006 as compared to 2005 since the kilns were in operation for all of 2006. Higher log sales revenue of $0.6 million also contributed to the increase in revenues. An increase in cherry export log sales as a result of greater market demand and an increase in saw log sales were the primary factors contributing to the increase. Offsetting these increases was a decline in cherry veneer log sales due to lower volumes of cherry veneer logs harvested because of unfavorable weather conditions.

**2005 Compared with 2004**

Operating revenues for the Timber segment increased $5.3 million in 2005 as compared with 2004. This increase can be partially attributed to an increase in kiln dry lumber sales of $2.2 million largely due to an increase in cherry lumber sales volumes of 1.6 million board feet. While there was a decline in kiln dry lumber sales volumes from other species (1.1 million board feet), the revenue from those species is not significant. Cherry kiln dry lumber revenues represent over 90% of the Timber segment s total kiln dry lumber revenues. The increase in volume is a result of the addition of two new kilns as discussed above, allowing for an increase in the amount of kiln dry lumber that can be processed. In addition, green lumber sales also increased by $1.4 million due to increased sales of maple green lumber primarily as a result of favorable weather conditions that allowed for an increase in harvesting.

**Earnings**

**2006 Compared with 2005**

The Timber segment earnings in 2006 were $5.7 million, an increase of $0.7 million when compared with earnings of $5.0 million in 2005. Higher margins from kiln dry lumber sales and cherry export log sales accounted for the earnings increase.

**2005 Compared with 2004**

The Timber segment earnings in 2005 were $5.0 million, a decrease of $0.6 million when compared with earnings of $5.6 million in 2004. Increases in the cost of goods sold during 2005 due to a greater amount of timber being harvested on purchased stumpage, which has a higher cost basis than other raw material sources, is primarily responsible for the earnings decline. Also contributing to the decline were overall increases in operating expenses due to higher utility costs. Partially offsetting these declines in earnings were the increased sales of kiln dry lumber and green lumber discussed above, as well as the favorable earnings impact associated with the non-recurrence of a $0.8 million loss recorded in 2004 related to the Company s fiscal 2003 sale of timber properties. In 2004, the Company received final timber cruise information of the properties it sold in 2003 and, based on that information, determined that property records pertaining to $1.3 million of timber property were not properly shown as having been transferred to the purchaser. As a result, the Company removed those assets from its property records and adjusted the previously recognized gain downward by recognizing a loss of $0.8 million.

**ALL OTHER AND CORPORATE OPERATIONS**

All Other and Corporate Operations primarily includes the operations of Horizon LFG, Horizon Power, former International segment activity other than the activity from the Czech Republic operations, 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 Operations of Unconsolidated Subsidiaries on the Consolidated Statement 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. Horizon Power also owns a gas-powered turbine and other assets which it had planned to use in the development of a co-generation plant. The Company is in the process of selling these

41

assets. The former International segment activity primarily consists of project development activities, the largest being projects in Italy and Bulgaria.

**Earnings**

**2006 Compared with 2005**

All Other and Corporate operations experienced income of $0.2 million in 2006, which was $7.1 million greater than a loss of $6.9 million in 2005. The increase is due primarily to the non-recurrence of $4.5 million of impairment charges recorded in 2005, as discussed below. Also contributing to the increase were higher interest income ($4.7 million) during 2006, resulting primarily from the investment of proceeds from the sale of U.E. in July 2005, combined with higher average interest rates in 2006 versus 2005. These increases were partially offset by higher operating expenses ($1.3 million) and lower margins on landfill gas sales ($0.5 million).

**2005 Compared with 2004**

All Other and Corporate operations experienced a loss of $6.9 million in 2005, which was $1.2 million greater than a loss of $5.7 million in 2004. During 2005, Horizon Power recorded a $2.7 million impairment in the value of its 50% investment in ESNE. Management determined that there was a decline in the fair market value of ESNE that was other than temporary in nature given continuing high commodity prices for natural gas and the negative impact these prices had on operations. ESNE has experienced losses over the last few years. It also recorded a $1.8 million impairment of the gas-powered turbine mentioned above. This impairment was based on a review of current market prices for similar turbines. However, these impairments were partially offset by higher equity method income from Horizon Power s investments in Seneca Energy and Model City ($1.4 million). Horizon LFG s earnings decreased by $1.3 million due to lower margins on gas sales. The overall decreases experienced by Horizon Power and Horizon LFG were partially offset by a $1.7 million improvement in the losses experienced by the former International segment, largely due to lower project development costs, and a $1.2 million improvement in earnings of Corporate operations.

**INTEREST INCOME**

Interest income was $3.8 million higher in 2006 compared to 2005. As discussed in the earnings discussion by segment above, the main reasons for this increase were strong cash flow from operations, the investment of proceeds from the sale of U.E. in July 2005 and higher average annual interest rates. Additionally, interest income on a pension related asset in accordance with the New York rate case settlement agreement increased by $0.5 million.

Interest income was $4.7 million higher in 2005 compared to 2004. As discussed in the earnings discussion by segment above, the main reason for this increase was the accrual of $3.7 million in interest on a pension related asset in accordance with the New York rate case settlement agreement that was completed in 2005.

**OTHER INCOME**

Other income was $9.9 million lower in 2006 compared to 2005. As discussed in the earnings discussion by segment above, the main reasons for this decrease included non-recurring gains recorded during 2005 in the Pipeline and Storage segment related to the sale of base gas ($2.6 million), and the disposition of insurance proceeds ($3.9 million) received in prior years for which a contingency was resolved.

Other income was $9.8 million higher in 2005 compared to 2004. As discussed in the earnings discussion by segment above, the main reasons for this increase included a $2.6 million gain in the Pipeline and Storage segment associated with a FERC approved sale of base gas in 2005 and a $3.9 million gain in the Pipeline and Storage segment associated with insurance proceeds received in prior years for which a contingency was resolved during 2005.

Table of Contents

## INTEREST CHARGES

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

Interest on long-term debt decreased $0.6 million in 2006 and $9.7 million in 2005. The decrease in 2005 was primarily the result of a lower average amount of long-term debt outstanding.

Other interest charges were $3.1 million lower in 2006 compared to 2005. The decrease resulted primarily from the non-recurrence of $2.1 million of interest expense, discussed below, recorded by the Utility segment in 2005 and a lower average amount of short-term debt outstanding during 2006.

Other interest charges were $2.3 million higher in 2005 compared to 2004. The increase resulted mainly from $2.1 million of interest expense recorded by the Utility segment as part of an adjustment to a regulatory liability recorded for previous over-collections of New York State gross receipts tax.

## 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 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Millions) | |
| Provided by Operating Activities | $ 471.4 | $ 317.3 | $ 437.1 |
| Capital Expenditures | (294.2) | (219.5) | (172.3) |
| Net Proceeds from Sale of Foreign Subsidiary | | 111.6 | |
| Net Proceeds from Sale of Oil and Gas Producing Properties | | 1.4 | 7.1 |
| Other Investing Activities | (3.2) | 3.2 | 2.0 |
| Change in Short-Term Debt | | (115.4) | 38.6 |
| Reduction of Long-Term Debt | (9.8) | (13.3) | (243.1) |
| Issuance of Common Stock | 23.3 | 20.3 | 23.8 |
| Dividends Paid on Common Stock | (98.2) | (94.1) | (89.1) |
| Dividends Paid to Minority Interest | | (12.7) | |
| Excess Tax Benefits Associated with Stock- Based Compensation Awards | 6.5 | | |
| Shares Repurchased under Repurchase Plan | (85.2) | | |
| Effect of Exchange Rates on Cash | 1.4 | 1.3 | 3.5 |
| Net Increase in Cash and Temporary Cash Investments | $ 12.0 | $ 0.1 | $ 7.6 |

## OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, impairment of investment in partnership, deferred income taxes, income or loss from unconsolidated subsidiaries net of cash distributions, minority interest in foreign subsidiaries, loss on sale of timber properties, gain on sale of oil and gas producing properties, and gain on the 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, no cost collars, options and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $471.4 million in 2006, an increase of $154.1 million compared with the $317.3 million provided by operating activities in 2005. Higher oil and gas revenues in the Exploration and Production segment were primarily responsible for the increase. A decrease in hedging collateral deposits at September 30, 2006 in the Exploration and Production and Energy Marketing segments also contributed to the increase. Hedging collateral deposits serve as collateral for open positions on exchange-traded futures contracts, exchange-traded options and over-the-counter swaps and collars. The decrease from the prior year is reflective of lower natural gas prices and a smaller number of derivative financial instruments outstanding at September 30, 2006 verses September 30, 2005. These increases were partially offset by the loss of positive cash flow from the Company s former Czech Republic operations, which were sold in July 2005.

**INVESTING CASH FLOW**

**Expenditures for Long-Lived Assets**

The Company s expenditures for long-lived assets totaled $294.2 million in 2006. The table below presents these expenditures:

| | Year Ended September 30, 2006 Total Expenditures For Long-Lived Assets (Millions) | |
|---|---|---|
| Utility | $ | 54.4 |
| Pipeline and Storage | | 26.0 |
| Exploration and Production | | 208.3 |
| Timber | | 2.3 |
| All Other and Corporate | | 3.2 |
| | $ | 294.2 |

**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 made 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 $41.8 million for the Canadian region, $103.4 million for the Gulf Coast region ($102.8 million for the off-shore program in the Gulf of Mexico), $36.1 million for the West Coast region and $27.0 million for the Appalachian region. The significant amount spent in the Gulf Coast region is related to high commodity prices, which has improved the economics of investment in the area, plus projected royalty relief. These amounts included approximately $55.6 million spent to develop proved undeveloped reserves.

**Timber**

The majority of the Timber segment capital expenditures were made for purchases of equipment for Highland s sawmill and kiln operations.

**Estimated Capital Expenditures**

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

| | Year Ended September 30 2007 | 2008 (Millions) | 2009 |
|---|---|---|---|
| Utility | $ 56.0 | $ 56.0 | $ 57.0 |
| Pipeline and Storage | 62.0 | 110.0 | 84.0 |
| Exploration and Production(1) | 212.0 | 207.0 | 243.0 |
| Timber | 4.0 | 1.0 | 1.0 |
| | $ 334.0 | $ 374.0 | $ 385.0 |

(1) Includes estimated expenditures for the years ended September 30, 2007, 2008 and 2009 of approximately $23 million, $22 million and $25 million, respectively, to develop proved undeveloped reserves.

Estimated capital expenditures for the Utility segment in 2007 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 2007 will be concentrated in the replacement of transmission and storage lines, reconditioning of storage wells and improvements of compressor stations.* The estimated capital expenditures for 2007 also includes $39.0 million for the Empire Connector project as discussed below.

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. In October 2005, Empire filed an application with the FERC for the authority to build and operate the Empire Connector project to expand its natural gas pipeline operations to serve new markets in New York and elsewhere in the Northeast by extending the Empire Pipeline. The application also asks that Empire s existing business and facilities be brought under FERC jurisdiction, and that FERC approve rates for Empire s existing and proposed services. Assuming the proposed Millennium Pipeline is constructed, the Empire Connector will provide an upstream supply link for the Millennium Pipeline and will transport Canadian and other natural gas supplies to downstream customers, including KeySpan Gas East Corporation, which has entered into precedent agreements to subscribe for at least 150 MDth per day of natural gas transportation service through the Empire State Pipeline and the Millennium Pipeline systems.* The Empire Connector will be designed to move up to approximately 250 MDth of natural gas per day.* In July 2006, Empire revised the planned in-service date for the Empire Connector to extend beyond its original November 2007 target. The new targeted in-service date is November 2008, or sooner if feasible.* FERC issued on July 20, 2006 a preliminary determination regarding non-environmental aspects of the application, in response to which Empire made a request for rehearing on August 21, 2006. Empire anticipates that FERC will issue a final certificate authorizing construction and operation of the project on or about December 2006, after which Empire will have to decide whether it will accept the final approval on the terms contained therein.* Refer to the Rate and Regulatory Matters section that follows for further discussion of this matter. The forecasted expenditures for this project over the next three years are as follows: $39.0 million in 2007, $85.0 million in 2008, and $22.0 million in 2009.* These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The Company anticipates financing this project with cash on hand and/or through the use of the Company s bi-lateral lines of credit.* As of September 30, 2006, the Company had incurred approximately $6.0 million in costs (all of which have been reserved) related to this project. Of this amount, $2.0 million, $3.4 million and $0.6 million were incurred during the years ended September 30, 2006, 2005 and 2004, respectively.

The Company also has plans to expand Supply Corporation s existing interconnect with Empire at Pendleton, New York. Compression will be added to allow Supply Corporation transportation and storage volumes to be delivered to Empire, which is operated at higher pressures than Supply Corporation s system.* The Pendleton Compression project will be a key strategic expansion for Supply Corporation, allowing access to both Empire and Millennium markets to the east, as well as for Empire, providing its shippers with access to storage services and Supply Corporation s array of interconnects. Supply Corporation is in the process of negotiating customer agreement(s), and expects to complete design and launch the regulatory approval process in late 2006.* There have been no costs incurred by the Company related to this project as of September 30, 2006, and the forecasted expenditures for this project over the next three years are as follows: $0 in 2007, $3.0 million in 2008, and $1.0 million in 2009.* These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The target in-service date for the Pendleton Compression project is contingent upon the Millennium/Empire Connector timeline.* Accordingly, Supply Corporation anticipates that most of the capital spending associated with this expansion will occur in fiscal 2008.*

Supply Corporation continues to view the Tuscarora Extension project as an important link to Millennium and potential storage development in the Corning, New York area.* The new pipeline, which would expand the Supply Corporation system from its Tuscarora storage field to the intersection of the proposed Millennium and Empire Connector pipelines, will be designed initially to transport up to approximately 130 MDth of natural gas per day. It may also provide Supply Corporation with the opportunity to increase the deliverability of the existing Tuscarora storage field.* The project timeline relies on market development, and should the market mature, the Company anticipates financing the Tuscarora Extension with cash on hand and/or through the use of the Company s bi-lateral lines of credit.* There have been no costs incurred by the Company related to this project as of September 30, 2006, and the forecasted expenditures for this project over the next three years are as follows: $0 in 2007 and 2008, and $39.0 million in 2009.* These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The Company has not yet filed an application with the FERC for the authority to build and operate the Tuscarora Extension.

Estimated capital expenditures in 2007 for the Exploration and Production segment include approximately $34.0 million for Canada, $100.0 million for the Gulf Coast region ($98.0 million on the off-shore program in the Gulf of Mexico), $43.0 million for the West Coast region and $35.0 million for the Appalachian region.*

Estimated capital expenditures in 2007 in the Timber segment will be concentrated on the purchase of new equipment 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, 2006. 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 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 (bi-lateral) 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 $445.0 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 from September 30, 2005 through September 30, 2010. At September 30, 2006, the Company s debt to capitalization ratio (as calculated under the facility) was .44. The constraints specified in the committed credit facility would permit an additional $1.56 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 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, 2006, the Company would have been permitted to issue up to a maximum of $1.03 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 $399.0 million (or 36%) of the Company s long-term debt (as of September 30, 2006) 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 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, 2006, the Company had no debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 6.4% at both September 30, 2006 and September 30, 2005. Refer to Interest Rate Risk in this Item for a more detailed breakdown of the Company s embedded cost of long-term debt.

The Company has an effective registration statement on file with the SEC under which it has available capacity to issue an additional $550.0 million of debt and equity securities under the Securities Act of 1933. The Company may sell all or a portion of the remaining registered securities if warranted by market conditions and the Company s capital requirements. Any offer and sale of the above mentioned $550.0 million of debt and equity securities will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

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.

On December 8, 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 8 million shares in the open market or through privately negotiated transactions. As of

Table of Contents

September 30, 2006, the Company has repurchased 2,526,550 shares under this program, funded with cash provided by operating activities. In the future, it is expected that this share repurchase program will continue to be funded with cash provided by operating activities and/or through the use of the Company s bi-lateral lines of credit.* It is expected that open market repurchases will continue from time to time depending on market conditions.*

## 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 $44.0 million. These leases have been entered into for the use of buildings, vehicles, construction tools, meters, computer equipment 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 $7.1 million. The Company has guaranteed 50%, or $3.5 million, of these capital lease commitments.

## CONTRACTUAL OBLIGATIONS

The following table summarizes the Company s expected future contractual cash obligations as of September 30, 2006, and the twelve-month periods over which they occur:

| | Payments by Expected Maturity Dates | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2007 | 2008 | 2009 | 2010 | 2011 | Thereafter | Total |
| | | | | (Millions) | | | |
| Long-Term Debt, including interest expense(1) | $ 93.7 | $ 266.0 | $ 154.7 | $ 51.8 | $ 238.9 | $ 776.7 | $ 1,581.8 |
| Operating Lease Obligations | $ 8.1 | $ 7.2 | $ 6.0 | $ 4.3 | $ 2.7 | $ 15.7 | $ 44.0 |
| Capital Lease Obligations | $ 1.1 | $ 0.9 | $ 0.5 | $ 0.4 | $ 0.4 | $ 0.2 | $ 3.5 |
| Purchase Obligations: | | | | | | | |
| Gas Purchase Contracts(2) | $ 742.8 | $ 149.4 | $ 17.7 | $ 6.9 | $ 6.5 | $ 64.7 | $ 988.0 |
| Transportation and Storage Contracts | $ 50.7 | $ 45.8 | $ 31.2 | $ 10.7 | $ 3.4 | $ 4.1 | $ 145.9 |
| Other | $ 25.0 | $ 2.9 | $ 2.0 | $ 2.0 | $ 1.8 | $ 4.6 | $ 38.3 |

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

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

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 the 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 legal proceedings disclosed in Item 3 of this report, 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 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 approximately 77% of the Company s domestic 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 2006, the Company contributed $20.9 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2007 will be in the range of $15.0 million to $20.0 million.* The Company expects that all subsidiaries having domestic 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 for substantially all domestic retired employees under a post-retirement benefit plan (Post-Retirement Plan). The Company has been making contributions to the Post-Retirement Plan over the last several years and anticipates that it will continue making contributions to the Post-Retirement Plan.* During 2006, the Company contributed $39.3 million to the Post-Retirement Plan. The Company anticipates that the annual contribution to the Post-Retirement Plan in 2007 will be in the range of $35.0 million to $45.0 million.* The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.*

A capital loss carryover of $25.1 million exists at September 30, 2006, which expires if not utilized by September 30, 2008. Although realization is not assured, management determined that it is more likely than not that the entire deferred tax asset associated with this carryover will be realized during the carryover period. As such, the valuation allowance of $2.9 million was reversed during 2006 as discussed under Exploration and Production in the Results of Operations section above.

A deferred tax asset of $9.0 million relating to Canadian operations exists at September 30, 2006. Although realization is not assured, management determined that it is more likely than not that future taxable income will be generated in Canada to fully utilize this asset, and as such, no valuation allowance was provided.

**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, options 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, 2006 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 Inside

FERC 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, 2006. At September 30, 2006, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2009.

***Natural Gas Price Swap Agreements***

| | Expected Maturity Dates | | | |
|---|---|---|---|---|
| | **2007** | **2008** | **2009** | **Total** |
| Notional Quantities (Equivalent Bcf) | 3.9 | 2.8 | 0.7 | 7.4 |
| Weighted Average Fixed Rate (per Mcf) | $ 6.95 | $ 7.26 | $ 8.63 | $ 7.24 |
| Weighted Average Variable Rate (per Mcf) | $ 7.29 | $ 8.37 | $ 8.84 | $ 7.85 |

***Crude Oil Price Swap Agreements***

| | Expected Maturity Dates | | |
|---|---|---|---|
| | **2007** | **2008** | **Total** |
| Notional Quantities (Equivalent bbls) | 855,000 | 45,000 | 900,000 |
| Weighted Average Fixed Rate (per bbl) | $ 37.03 | $ 39.00 | $ 37.13 |
| Weighted Average Variable Rate (per bbl) | $ 65.47 | $ 68.90 | $ 65.64 |

At September 30, 2006, the Company would have had to pay its respective counterparties an aggregate of approximately $7.4 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have had to pay an aggregate of approximately $27.6 million to its counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2006.

At September 30, 2005, the Company had natural gas price swap agreements covering 18.8 Bcf at a weighted average fixed rate of $5.73 per Mcf. The Company also had crude oil price swap agreements covering 2,835,000 bbls at a weighted average fixed rate of $35.09 per bbl. The decrease in natural gas price swap agreements from September 2005 to September 2006 is largely attributable to management s decision to utilize more no cost collars as a means of hedging natural gas production in the Exploration and Production segment. The decrease in crude oil price swap agreements is primarily due to the fact that the Company has not been entering into new swap agreements for its West Coast crude oil production. This decision is related to the price, or basis, differential that exists between the Company s West Coast heavy sour crude oil and the West Texas Intermediate light sweet crude oil that is quoted on the NYMEX. The Company has been unable to hedge against changes in the basis differential.

The following table discloses the notional quantities, the weighted average ceiling price and the weighted average floor price for the no cost collars used by the Company to manage natural gas price risk. The no cost collars provide for the Company to receive monthly payments from (or make payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). At September 30, 2006, the Company had not entered into any natural gas or crude oil no cost collars extending beyond 2008.

***No Cost Collars***

**Expected Maturity Dates**

| | 2007 | 2008 | Total |
|---|---|---|---|
| Natural Gas | | | |
| Notional Quantities (Equivalent Bcf) | 5.7 | 1.4 | 7.1 |
| Weighted Average Ceiling Price (per Mcf) | $ 17.45 | $ 16.45 | $ 17.25 |
| Weighted Average Floor Price (per Mcf) | $ 8.12 | $ 8.83 | $ 8.26 |

Table of Contents

| | 2007 |
|---|---|
| Crude Oil | |
| Notional Quantities (Equivalent bbls) | 180,000 |
| Weighted Average Ceiling Price (per bbl) | $ 77.00 |
| Weighted Average Floor Price (per bbl) | $ 70.00 |

At September 30, 2006, the Company would have received an aggregate of approximately $10.4 million to terminate the natural gas no cost collars outstanding at that date. The Company would have received $0.9 million to terminate the crude oil no cost collars at September 30, 2006.

At September 30, 2005, the Company had natural gas no cost collars covering 8.5 Bcf at a weighted average floor price of $7.54 per Mcf and a weighted average ceiling price of $15.62 per Mcf. The Company did not have any outstanding crude oil no cost collars at September 30, 2005. The decrease in natural gas collars from September 2005 to September 2006 is due to management s decision to curtail hedging activity in the fourth quarter of 2006 due to the forecast of a more active hurricane season in 2006. In 2005, the Company recognized a $5.1 million mark-to-market adjustment related to derivative financial instruments that no longer qualified as effective hedges due to production delays caused by Hurricane Rita, and management wanted to prevent this from recurring in 2006. When the hurricane season did not turn out to be as active as everyone had forecasted, the pricing strip at that time was so low that management elected to hold off on some of the hedging. Management is reviewing that policy and is in the process of looking at layering in more hedges in the future.*

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, 2006, the Company held no futures contracts with maturity dates extending beyond 2012.

***Futures Contracts***

| | Expected Maturity Dates | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | Total |
| Net Contract Volumes Purchased (Sold) (Equivalent Bcf) | 7.2 | (0.1) | (0.1) | | (1) | (1) | 7.0 |
| Weighted Average Contract Price (per Mcf) | $ 9.63 | $ 9.85 | $ 9.57 | NA | $ 6.99 | $ 8.68 | $ 9.67 |
| Weighted Average Settlement Price (per Mcf) | $ 10.02 | $ 9.58 | $ 9.14 | NA | $ 6.91 | $ 9.29 | $ 9.89 |

(1) The Energy Marketing segment has purchased 4 and 6 futures contracts (1 contract = 2,500 Dth) for 2011 and 2012, respectively.

At September 30, 2006, the Company would have had to pay $4.9 million to terminate these futures contracts.

At September 30, 2005, the Company had futures contracts covering 2.2 Bcf (net short position) at a weighted average contract price of $8.63 per Mcf.

The increase in net long positions in 2006 was due to the decrease in natural gas prices in the summer months which led to an increase in fixed price sales commitments. These commitments were hedged with long positions in the futures market.

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 the parent companies of the respective counterparties to its derivatives. At September 30, 2006, the Company used six counterparties for its over the counter derivatives. At September 30, 2006, no individual counterparty represented greater than 39% of total credit risk (measured as volumes hedged by an individual counterparty as

Table of Contents

a percentage of the Company s total volumes hedged). All of the counterparties (or the parent of the counterparty) were rated as investment grade entities at September 30, 2006.

**Exchange Rate Risk**

The Exploration and Production segment s investment in Canada is valued in Canadian dollars, and, as such, this investment is subject to currency exchange risk when the Canadian dollars are translated into U.S. dollars. This exchange rate risk to the Company s investment in Canada results in increases or decreases to the CTA, a component of Accumulated Other Comprehensive Income/Loss on the Consolidated Balance Sheets. When the foreign currency increases in value in relation to the U.S. dollar, there is a positive adjustment to CTA. When the foreign currency decreases in value in relation to the U.S. dollar, there is a negative adjustment to CTA.

**Interest Rate Risk**

The Company s exposure to interest rate risk arises primarily from the $22.8 million of variable rate debt included in Other Notes in the table below. To mitigate this risk, the Company uses an interest rate collar to limit interest rate fluctuations. Under the interest rate collar the Company makes quarterly payments to (or receives payments from) another party when a variable rate falls below an established floor rate (the Company pays the counterparty) or exceeds an established ceiling rate (the Company receives payment from the counterparty). Under the terms of the collar, which extends until 2009, the variable rate is based on LIBOR. The floor rate of the collar is 5.15% and the ceiling rate is 9.375%. The Company would have had to pay $0.1 million to terminate the interest rate collar at September 30, 2006.

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, 2006:

| | Principal Amounts by Expected Maturity Dates (Dollars in millions) | | | | | | |
|---|---|---|---|---|---|---|---|
| | **2007** | **2008** | **2009** | **2010** | **2011** | **Thereafter** | **Total** |
| **National Fuel Gas Company** | | | | | | | |
| Long-Term Fixed Rate Debt | $ | $ 200.0 | $ 100.0 | $ | $ 200.0 | $ 595.7 | $ 1,095.7 |
| Weighted Average Interest Rate Paid | | 6.3% | 6.0% | | 7.5% | 6.2% | 6.4% |
| Fair Value = $1,125.2 | | | | | | | |
| **Other Notes** | | | | | | | |
| Long-Term Debt(1) | $ 22.9 | $ | $ | $ | $ | $ | $ 22.9 |
| Weighted Average Interest Rate Paid(2) | 6.5% | | | | | | 6.5% |
| Fair Value = $22.9 | | | | | | | |

(1) $22.8 million is variable rate debt. It is the Company s intention to pay off these notes within one year. As such, the notes have been classified as current.

(2) Weighted average interest rate excludes the impact of an interest rate collar on $22.8 million of variable rate debt.

**RATE AND REGULATORY MATTERS**

**Energy Policy Act**

On August 8, 2005, President Bush signed into law the Energy Policy Act, which, among other things, included PUHCA 2005. PUHCA 2005 repealed PUHCA 1935 effective February 8, 2006. Since that date, the Company has been free from PUHCA 1935 s broad regulatory provisions, including provisions relating to the issuance of securities, sales and acquisitions of securities and utility assets, intra-company transactions and limitations on diversification. PUHCA 2005, among other things, grants the FERC and state public utility regulatory commissions access to certain books and records of companies in holding company systems. On December 8, 2005, the FERC issued Order 667 to implement PUHCA 2005. The FERC clarified certain aspects of Order 667 in Order 667-A, issued on April 24, 2006. On June 15, 2006, pursuant to the FERC s regulations, the Company filed a notification of holding company status with the FERC. Also on that date, the Company filed an exemption request with the FERC, requesting exemption of the Company and its subsidiaries from the FERC s regulations under PUHCA 2005. The exemption request has been granted by operation of law pursuant to the FERC s regulations.

**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 August 27, 2004, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues beginning October 1, 2004. Various parties opposed the filing. On April 15, 2005, Distribution Corporation, the parties and others executed an agreement settling all outstanding issues. In an order issued July 22, 2005, the NYPSC approved the April 15, 2005 settlement agreement, substantially as filed, for an effective date of August 1, 2005. The settlement agreement provides for a rate increase of $21 million by means of the elimination of bill credits ($5.8 million) and an increase in base rates ($15.2 million). For the two-year term of the agreement and thereafter, the return on equity level above which earnings must be shared with rate payers is 11.5%.

**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 includes an increase in 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 new rates will become effective January 1, 2007.

On June 8, 2006, the NTSB issued safety recommendations to Distribution Corporation as a result of an investigation of a natural gas explosion that occurred on Distribution Corporation s system in Dubois, Pennsylvania in August 2004. The explosion destroyed a residence, resulting in the death of two people who lived there, and damaged a number of other houses in the immediate vicinity.

The NTSB and Distribution Corporation differ in their assessment of the probable cause of the explosion. The NTSB determined that the probable cause was the fracture of a defective butt-fusion joint which had joined two sections of plastic pipe, and the failure of Distribution Corporation to have an adequate program to inspect butt-fusion joints and replace those joints not meeting its inspection criteria. Distribution Corporation had submitted to the NTSB a proposed determination of probable cause that was substantially different, namely, that the probable cause was the improper excavation and backfill operations of a third party working in the vicinity of Distribution Corporation s pipeline. Distribution Corporation also had raised issues concerning the testing standards employed in the NTSB investigation. Distribution Corporation is presently reviewing alternatives by which to seek review of the NTSB s findings and conclusions to ensure that the NTSB considered all relevant evidence, including the report of Distribution Corporation s third-party plastic pipe expert and other relevant evidence, in reaching its determination of probable cause.

The NTSB s safety recommendations to Distribution Corporation involved revisions to its butt-fusion procedures for joining plastic pipe, and revisions to its procedures for qualifying personnel who perform plastic fusions. Although not required by law to do so, Distribution Corporation is presently implementing those recommendations.

The NTSB also issued safety recommendations to the PaPUC and certain other parties. The recommendation to the PaPUC was to require an analysis of the integrity of butt-fusion joints in Distribution Corporation s system and replacement of those joints that are determined to have unacceptable characteristics. Distribution Corporation is working cooperatively with the Staff of the PaPUC to permit the PaPUC to undertake the analysis recommended by the NTSB. Specifically, Distribution has done the following, in agreement with the PaPUC Staff:

(i) Distribution Corporation uncovered a limited number of butt-fusions at two locations designated by the PaPUC Staff;

(ii) Commencing July 6, 2006, Distribution Corporation has uncovered additional butt-fusions throughout its Pennsylvania service area as it has uncovered facilities for other purposes; when a butt-fusion has been uncovered, Distribution Corporation has notified the designated PaPUC Staff representative to permit inspection of the quality of the fusion. Distribution Corporation has removed a number of fusions for further evaluation.

Distribution Corporation met with the PaPUC Staff in August 2006 to review findings to date and to discuss further procedures to facilitate the analysis. Distribution Corporation and the PaPUC Staff agreed to submit several of the butt-fusion specimens removed during the inspection process to an independent testing laboratory to assess the integrity of the fusions (and to provide an evaluation of the sampling procedure employed). Distribution Corporation and the PaPUC Staff have agreed upon procedures to test the butt-fusion specimens. Distribution Corporation anticipates that it will continue to meet with the PaPUC Staff to review findings pertaining to this matter and address any integrity concerns that may be identified.* At this time, Distribution Corporation is unable to predict the outcome of the analysis or of any negotiations or proceedings that may result from it. Distribution Corporation s response to the actions of the PaPUC will depend on its assessment of the validity of the PaPUC s analysis and conclusions.

Without admitting liability, Distribution Corporation has settled all significant third-party claims against it related to the explosion, for amounts that are immaterial in the aggregate to the Company. Distribution Corporation has been committed to providing safe and reliable service throughout its service territory and firmly believes, based on information presently known, that its system continues to be safe and reliable. According to the Plastics Pipe Institute, plastic pipe today accounts for over 90% of the pipe installed for the natural gas distribution industry in the United States and Canada. Distribution Corporation, along with many other natural gas utilities operating in the United States, has relied extensively upon the use of plastic pipe in its natural gas distribution system since the 1970s.

**Pipeline and Storage**

On April 7, 2006, the NYPSC, PaPUC and Pennsylvania Office of Consumer Advocate filed a complaint and a motion for summary disposition against Supply Corporation with the FERC under Sections 5(a) and 13 of the Natural Gas Act (NGA). The complainants alleged that Supply Corporation s rates were unjust and unreasonable, and that Supply Corporation was permitted to retain more gas from shippers than is necessary for fuel and loss. As a result, the complainants alleged, Supply Corporation has excess annual earnings of approximately $30 million to $35 million.

In their complaint, the complainants asked FERC (i) to find that Supply Corporation s rates are unjust and unreasonable, and (ii) to institute proceedings to determine the just and reasonable rates Supply Corporation will be authorized to charge prospectively. The complainants also asked FERC in their complaint (i) to determine whether Supply Corporation has the authority to make sales of gas retained from shippers, and (ii) if FERC concludes that Supply Corporation does not have such authority, to direct Supply Corporation to show cause why it should not be required to disgorge profits associated with such sales. In their motion for summary disposition, the complainants asked FERC (i) to find summarily that the rate at which Supply Corporation is permitted to retain gas from shippers for fuel and loss is unjust and unreasonable, (ii) to require Supply Corporation to make a compliance filing providing detailed information regarding its fuel and loss retention and use, and (iii) to establish just and reasonable fuel and loss percentages for Supply Corporation.

On June 23, 2006, FERC denied the complainants motion for summary disposition, set the matter for hearing and referred the complaint to a settlement Administrative Law Judge. On August 8, 2006, a presiding Administrative Law Judge was appointed and discovery activity began. On August 22, 2006, the presiding Administrative Law Judge established a procedural schedule under which he would issue an initial recommended decision by August 8, 2007. Discovery and settlement activity continued. On September 26, 2006, the presiding Administrative Law Judge granted Supply Corporation s unopposed motion to suspend the procedural schedule because the active parties had reached a settlement in principle.

On November 17, 2006, Supply Corporation filed a motion asking FERC to approve an uncontested settlement of the proceeding. The proposed settlement would be implemented when and if FERC approves the settlement, but if approved would be effective as of December 1, 2006. The principal elements of the settlement are as follows:

(i) All participants have reached a negotiated resolution of all the issues raised or which could have been raised in the proceeding, including the claim that Supply Corporation should disgorge all previous efficiency gas sales profits.

(ii) Supply Corporation s gas retention allowances on transportation services will decrease from 2% to 1.4%, which will reduce Supply Corporation s future revenue from sales of excess efficiency gas. For example, if pre-settlement Supply Corporation received 100 Dth of gas for transportation under its firm transportation rate schedule, Supply Corporation would retain 2 Dth for fuel, loss and company use. Post-settlement, Supply Corporation would retain a total of 1.4 Dth for the combination of fuel, company use and lost and unaccounted for (LAUF). Supply Corporation may continue to sell the excess retained gas, if any, that is not consumed or lost in operations (the efficiency gas ) and keep the proceeds. However, any profit from the purchase and sale of gas to cash out shipper imbalances will continue to be accounted for separately and refunded to customers. Supply Corporation will publicly file at FERC a semi-annual report disclosing, among other things, the quantity, price and accounting treatment of all sales of efficiency gas. The amount of net revenue from Supply Corporation s future sales of efficiency gas will depend upon the quantity of efficiency gas that becomes available for sale and the prices which Supply Corporation receives from selling that gas.*

(iii) Supply Corporation s annual depreciation rate for transmission plant will decrease to 2.9%, and its annual depreciation rate for storage plant will decrease to 2.23%. This will result in a decrease to Supply Corporation s depreciation expense by $5.623 million per year from the pre-settlement level of annual depreciation expense.*

(iv) The settlement does not change Supply Corporation s rates other than its gas retention allowances. No general rate cases or NGA Section 5 complaint may be filed by the settling parties to be effective before December 1, 2011. However, Supply Corporation may file limited NGA Section 4 rate cases as permitted by FERC for matters of general applicability to all pipelines (such as passing through some possible future greenhouse gas tax), and may propose seasonal rates.

(v) Supply Corporation s Other Post-Retirement Benefits Rate Allowance (the amount deemed to be recovered each year in rates to fund the Post-Retirement Plan benefits described in Note G Retirement Plan and Other Post-Retirement Benefits) will increase from about $4.736 million to $11.0 million per year. Supply Corporation will contribute its entire Other Post-Retirement Benefits Rate Allowance to the VEBA trusts and 401(h) account described in that Note G. About $2.5 million per year of the Other Post-Retirement Benefits Rate Allowance will be applied to fully amortize over the next five years Supply Corporation s entire other post-retirement benefits regulatory asset balance at December 1, 2006, which had been deferred for recovery under a 1995 rate case settlement. To the extent the remainder of the Other Post-

Table of Contents

Retirement Benefits Rate Allowance differs from the SFAS 106 expense that Supply Corporation actually accrues for the Post-Retirement Plan, that difference will be deferred for future recovery or refund as a regulatory asset or liability. See Note G Retirement Plan and Other Post-Retirement Benefits for extensive disclosure on the Post-Retirement Plan.

(vi) Supply Corporation s tariff provisions on discounting gas retention allowances will be amended so as to be consistent with FERC s current policy limiting fuel discounts. Certain pre-settlement discounts in gas retention allowances will also be incorporated into the tariff. The discounting changes described in this subparagraph (vi) are not expected to change Supply Corporation s earnings as compared to pre-settlement discounting practices.*

This matter will be resolved at FERC by either (i) FERC approval of a settlement, or (ii) the hearing process described above, in the course of which the presiding judge would issue initial recommended decision(s) which would be considered by FERC.* In that event, FERC would issue an order that would either be consistent or inconsistent with any recommended decision, after which any new rates would go into effect.* Supply Corporation expects the proposed settlement to be approved.* If this matter goes to hearing, Supply Corporation will vigorously oppose the complaint.*

Empire currently does not have a rate case on file with the NYPSC. Management will continue to monitor its financial position in the New York jurisdiction to determine the necessity of filing a rate case in the future.

Among the issues that will be resolved in connection with Empire s FERC application to build the Empire Connector are the rates and terms of service that would become applicable to all of Empire s business, effective upon Empire accepting the FERC certificate and placing its new facilities into service (currently targeted for November 2008, or sooner if feasible). At that time, Empire would become an interstate pipeline subject to FERC regulation.*

A preliminary determination was issued in the Empire Connector FERC proceeding on July 20, 2006, resolving the rate and other non-environmental issues subject to the outcome of pending rehearing requests and any future appeals, and requiring Empire to make a compliance filing with respect to certain non-environmental issues. Empire made its compliance filing on September 18, 2006. This filing developed initial rates applicable to Empire s existing services (as they would look under FERC regulation), based on a derived annual cost of service of $30.4 million. Included in this derived cost of service is a change of Empire s transmission plant annual depreciation rate from 4% to 2.5%, resulting in a reduction of $3.3 million in the filed-for cost of service. This depreciation change would have no impact on earnings because the resulting decrease in revenue would be matched by a decrease in depreciation expense. The initial rates developed from this cost of service are under a straight fixed variable rate design, where all fixed elements of cost of service would be recovered under a fixed monthly reservation charge, and costs which vary with throughput would be recovered in charges per Dth of throughput. This rate design would eliminate most of the revenue variability associated with weather.*

On September 13, 2006 the New York State Department of Environmental Conservation issued an Air State Facility Permit for the Oakfield compressor station, a part of the Empire Connector project. On October 13, 2006, FERC issued a final supplemental environmental impact statement on the Empire Connector project and the other related downstream projects, indicating that FERC has not identified any environmental reasons why those projects could not be built, and that it is the preferred alternative. The next steps at FERC would be the issuance and acceptance of Certificates of Public Convenience and Necessity on all the related projects, followed by additional environmental permits from the U.S. Army Corps of Engineers and state environmental agencies.* The Company expects that all the necessary permits will be obtained and accepted, firm service agreements signed, acceptable proposals for materials and construction-related services will be received and accepted, and the Empire Connector project will be built and in service by November 2008. *

**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

Table of Contents

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. The Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be $3.8 million.* This liability has been recorded on the Consolidated Balance Sheet at September 30, 2006. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and insurance proceeds.* Other than discussed in Note H (referred to below), the Company is currently not aware of any material additional exposure to environmental liabilities. However, adverse changes in environmental regulations or other factors could 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 March 2005, the FASB issued FIN 47, an interpretation of SFAS 143. FIN 47 provides additional guidance on the term conditional asset retirement obligation as used in SFAS 143, and in particular the standard clarifies when a Company must record a liability for a conditional asset retirement obligation. The Company has adopted FIN 47 as of September 30, 2006. Refer to Item 8 at Note B Asset Retirement Obligations for further disclosure regarding the impact of FIN 47 on the Company s consolidated financial statements.

In May 2005, the FASB issued SFAS 154. SFAS 154 replaces APB 20 and SFAS 3 and changes the requirements for the accounting for and reporting of a change in accounting principle. The Company s financial condition and results of operations will only be impacted by SFAS 154 if there are any accounting changes or corrections of errors in the future. For further discussion of SFAS 154 and its impact on the Company, refer to Item 8 at Note A Summary of Significant Accounting Policies.

In June 2006, the FASB issued FIN 48, an interpretation of SFAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes and reduces the diversity in current practice associated with the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return by defining a more-likely-than-not threshold regarding the sustainability of the position. The Company is currently evaluating the impact of FIN 48 on its consolidated financial statements. For further discussion of FIN 48 and its impact on the Company, refer to Item 8 at Note A Summary of Significant Accounting Policies.

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. The Company is currently evaluating the impact that the adoption of SFAS 157 will have on its consolidated financial statements. For further discussion of SFAS 157 and its impact on the Company, refer to Item 8 at Note A Summary of Significant Accounting Policies.

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. The Company is required to recognize the funded status of its benefit plans and the disclosure requirements of SFAS 158 by the fourth quarter of fiscal 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. If the Company recognized the funded status of its pension and post-retirement benefit plans at September 30, 2006, the Company s Consolidated Balance Sheet would reflect a liability of $220.8 million instead of the prepaid pension and post-retirement costs of $64.1 million and pension and post-retirement liabilities of $32.9 million that are currently presented on the balance sheet at September 30, 2006. The Company expects that it will record a regulatory asset for the majority of this liability with the remainder reflected in accumulated other comprehensive income (loss). The difference between what the Company

Table of Contents

currently records on its Consolidated Balance Sheet for its pension and post-retirement benefit obligations and what it will be required to record under SFAS 158 is due to certain unrecognized actuarial gains and losses and unrecognized prior service costs for both the pension and other post-retirement benefit plans as well as an unrecognized transition obligation for the other post-retirement benefit plan. These amounts are not required to be recorded on the Company s Consolidated Balance Sheet under the current accounting standards, but were instead amortized over a period of time.

## 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, those which are designated with an asterisk ( * ) and those which are identified by the use of the words anticipates, estimates, expects, intends, plans, predicts, projects, and similar expressions, are forward-looking statements as defined in the Priva 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. Changes in laws and regulations to which the Company is subject, including changes in tax, environmental, safety and employment laws and regulations;

2. Changes in economic conditions, including economic disruptions caused by terrorist activities, acts of war or major accidents;

3. Changes in demographic patterns and weather conditions, including the occurrence of severe weather such as hurricanes;

4. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment or valuation of derivative financial instruments or the Company s natural gas and oil reserves;

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

6. Changes in the availability and/or price of derivative financial instruments;

7. Changes in the price differentials between various types of oil;

8. Failure of the price differential between heavy sour crude oil and light sweet crude oil to return to its historical norm;

9. Inability to obtain new customers or retain existing ones;

10. Significant changes in competitive factors affecting the Company;

11. 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 gas), affiliate relationships, industry structure, franchise renewal, and environmental/safety requirements;

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

13. Significant changes from expectations in actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs or plans, including changes in the plans of the sponsors of the proposed Millennium Pipeline with respect to that project;

14. The nature and projected profitability of pending and potential projects and other investments;

15. Occurrences affecting the Company s ability to obtain funds from operations or from issuances of debt or equity securities to finance needed capital expenditures and other investments, including any downgrades in the Company s credit ratings;

16. Uncertainty of oil and gas reserve estimates;

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

18. Ability to successfully identify, drill for and produce economically viable natural gas and oil reserves;

19. Significant changes from expectations in the Company s actual production levels for natural gas or oil;

20. Regarding foreign operations, changes in trade and monetary policies, inflation and exchange rates, taxes, operating conditions, laws and regulations related to foreign operations, and political and governmental changes;

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

22. 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;

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

24. The cost and effects of legal and administrative claims against the Company;

25. Changes in actuarial assumptions and the return on assets with respect to the Company s retirement plan and post-retirement benefit plans;

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

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

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

**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, 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:

We have completed integrated audits of National Fuel Gas Company s fiscal 2006 and 2005 consolidated financial statements and of its internal control over financial reporting as of September 30, 2006, and an audit of its fiscal 2004 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

**Consolidated financial statements and financial statement schedule**

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, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2006 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. These financial statements and financial statement schedule are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes 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. We believe that our audits provide a reasonable basis for our opinion.

**Internal control over financial reporting**

Also, in our opinion, management s assessment, included in Management s Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of September 30, 2006 based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2006, based on criteria established in *Internal Control Integrated Framework* issued by the COSO. The Company s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management s assessment and on the effectiveness of the Company s internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management s assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides 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

**Table of Contents**

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
December 7, 2006

Table of Contents

## NATIONAL FUEL GAS COMPANY

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| | **(Thousands of dollars, except per common share amounts)** | | |
| **INCOME** | | | |
| **Operating Revenues** | $ 2,311,659 | $ 1,923,549 | $ 1,907,968 |
| **Operating Expenses** | | | |
| Purchased Gas | 1,267,562 | 959,827 | 949,452 |
| Operation and Maintenance | 413,726 | 404,517 | 385,519 |
| Property, Franchise and Other Taxes | 69,942 | 69,076 | 68,978 |
| Depreciation, Depletion and Amortization | 179,615 | 179,767 | 174,289 |
| Impairment of Oil and Gas Producing Properties | 104,739 | | |
| | 2,035,584 | 1,613,187 | 1,578,238 |
| Loss on Sale of Timber Properties | | | (1,252) |
| Gain on Sale of Oil and Gas Producing Properties | | | 4,645 |
| **Operating Income** | 276,075 | 310,362 | 333,123 |
| **Other Income (Expense):** | | | |
| Income from Unconsolidated Subsidiaries | 3,583 | 3,362 | 805 |
| Impairment of Investment in Partnership | | (4,158) | |
| Interest Income | 10,275 | 6,496 | 1,771 |
| Other Income | 2,825 | 12,744 | 2,908 |
| Interest Expense on Long-Term Debt | (72,629) | (73,244) | (82,989) |
| Other Interest Expense | (5,952) | (9,069) | (6,763) |
| **Income from Continuing Operations Before Income Taxes** | 214,177 | 246,493 | 248,855 |
| Income Tax Expense | 76,086 | 92,978 | 94,590 |
| **Income from Continuing Operations** | 138,091 | 153,515 | 154,265 |
| **Discontinued Operations:** | | | |
| Income from Operations, Net of Tax | | 10,199 | 12,321 |
| Gain on Disposal, Net of Tax | | 25,774 | |
| **Income from Discontinued Operations** | | 35,973 | 12,321 |
| **Net Income Available for Common Stock** | 138,091 | 189,488 | 166,586 |
| **EARNINGS REINVESTED IN THE BUSINESS** | | | |
| Balance at Beginning of Year | 813,020 | 718,926 | 642,690 |

| | | | | | | |
|---|---|---|---|---|---|---|
| | | 951,111 | | 908,414 | | 809,276 |
| Share Repurchases | | 66,269 | | | | |
| Dividends on Common Stock | | 98,829 | | 95,394 | | 90,350 |
| **Balance at End of Year** | $ | 786,013 | $ | 813,020 | $ | 718,926 |
| **Earnings Per Common Share:** | | | | | | |
| Basic: | | | | | | |
| Income from Continuing Operations | $ | 1.64 | $ | 1.84 | $ | 1.88 |
| Income from Discontinued Operations | | | | 0.43 | | 0.15 |
| **Net Income Available for Common Stock** | $ | 1.64 | $ | 2.27 | $ | 2.03 |
| Diluted: | | | | | | |
| Income from Continuing Operations | $ | 1.61 | $ | 1.81 | $ | 1.86 |
| Income from Discontinued Operations | | | | 0.42 | | 0.15 |
| **Net Income Available for Common Stock** | $ | 1.61 | $ | 2.23 | $ | 2.01 |
| **Weighted Average Common Shares Outstanding:** | | | | | | |
| Used in Basic Calculation | | 84,030,118 | | 83,541,627 | | 82,045,535 |
| Used in Diluted Calculation | | 86,028,466 | | 85,029,131 | | 82,900,438 |

See Notes to Consolidated Financial Statements

Table of Contents

**NATIONAL FUEL GAS COMPANY**

**CONSOLIDATED BALANCE SHEETS**

| | At September 30 2006 | 2005 |
|---|---|---|
| | (Thousands of dollars) | |
| **ASSETS** | | |
| **Property, Plant and Equipment** | $ 4,703,040 | $ 4,423,255 |
| Less Accumulated Depreciation, Depletion and Amortization | 1,825,314 | 1,583,955 |
| | 2,877,726 | 2,839,300 |
| **Current Assets** | | |
| Cash and Temporary Cash Investments | 69,611 | 57,607 |
| Hedging Collateral Deposits | 19,676 | 77,784 |
| Receivables Net of Allowance for Uncollectible Accounts of $31,427 and $26,940, Respectively | 144,254 | 141,408 |
| Unbilled Utility Revenue | 25,538 | 20,465 |
| Gas Stored Underground | 59,461 | 64,529 |
| Materials and Supplies at average cost | 36,693 | 33,267 |
| Unrecovered Purchased Gas Costs | 12,970 | 14,817 |
| Prepaid Pension and Post-Retirement Benefit Costs | 64,125 | 14,404 |
| Other Current Assets | 63,723 | 67,351 |
| Deferred Income Taxes | 23,402 | 83,774 |
| | 519,453 | 575,406 |
| **Other Assets** | | |
| Recoverable Future Taxes | 79,511 | 85,000 |
| Unamortized Debt Expense | 15,492 | 17,567 |
| Other Regulatory Assets | 76,917 | 47,028 |
| Deferred Charges | 3,558 | 4,474 |
| Other Investments | 88,414 | 80,394 |
| Investments in Unconsolidated Subsidiaries | 11,590 | 12,658 |
| Goodwill | 5,476 | 5,476 |
| Intangible Assets | 31,498 | 42,302 |
| Fair Value of Derivative Financial Instruments | 11,305 | |
| Deferred Income Taxes | 9,003 | |
| Other | 4,388 | 15,677 |
| | 337,152 | 310,576 |
| **Total Assets** | $ 3,734,331 | $ 3,725,282 |

**CAPITALIZATION AND LIABILITIES**

| | | |
|---|---|---|
| **Capitalization:** | | |
| **Comprehensive Shareholders Equity** | | |
| Common Stock, $1 Par Value | | |
| Authorized 200,000,000 Shares; Issued and Outstanding 83,402,670 Shares and 84,356,748 Shares, Respectively | $ 83,403 | $ 84,357 |
| Paid In Capital | 543,730 | 529,834 |
| Earnings Reinvested in the Business | 786,013 | 813,020 |
| Total Common Shareholders Equity Before Items Of Other Comprehensive Income (Loss) | 1,413,146 | 1,427,211 |
| Accumulated Other Comprehensive Income (Loss) | 30,416 | (197,628) |
| **Total Comprehensive Shareholders Equity** | 1,443,562 | 1,229,583 |
| **Long-Term Debt, Net of Current Portion** | 1,095,675 | 1,119,012 |
| **Total Capitalization** | 2,539,237 | 2,348,595 |
| **Current and Accrued Liabilities** | | |
| Notes Payable to Banks and Commercial Paper | | |
| Current Portion of Long-Term Debt | 22,925 | 9,393 |
| Accounts Payable | 133,034 | 155,485 |
| Amounts Payable to Customers | 23,935 | 1,158 |
| Dividends Payable | 25,008 | 24,445 |
| Interest Payable on Long-Term Debt | 18,420 | 18,438 |
| Other Accruals and Current Liabilities | 27,040 | 44,596 |
| Fair Value of Derivative Financial Instruments | 39,983 | 209,072 |
| | 290,345 | 462,587 |
| **Deferred Credits** | | |
| Deferred Income Taxes | 544,502 | 489,720 |
| Taxes Refundable to Customers | 10,426 | 11,009 |
| Unamortized Investment Tax Credit | 6,094 | 6,796 |
| Cost of Removal Regulatory Liability | 85,076 | 90,396 |
| Other Regulatory Liabilities | 75,456 | 66,339 |
| Pension and Other Post-Retirement Liabilities | 32,918 | 143,687 |
| Asset Retirement Obligation | 77,392 | 41,411 |
| Other Deferred Credits | 72,885 | 64,742 |
| | 904,749 | 914,100 |
| **Commitments and Contingencies** | | |
| **Total Capitalization and Liabilities** | $ 3,734,331 | $ 3,725,282 |

See Notes to Consolidated Financial Statements

Table of Contents

**NATIONAL FUEL GAS COMPANY**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (Thousands of dollars) | | |
| **Operating Activities** | | | |
| Net Income Available for Common Stock | $ 138,091 | $ 189,488 | $ 166,586 |
| Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities: | | | |
| Gain on Sale of Discontinued Operations | | (27,386) | |
| Loss on Sale of Timber Properties | | | 1,252 |
| Gain on Sale of Oil and Gas Producing Properties | | | (4,645) |
| Impairment of Oil and Gas Producing Properties | 104,739 | | |
| Depreciation, Depletion and Amortization | 179,615 | 193,144 | 189,538 |
| Deferred Income Taxes | (5,230) | 40,388 | 40,329 |
| (Income) Loss from Unconsolidated Subsidiaries, Net of Cash Distributions | 1,067 | (1,372) | (19) |
| Impairment of Investment in Partnership | | 4,158 | |
| Minority Interest in Foreign Subsidiaries | | 2,645 | 1,933 |
| Excess Tax Benefits Associated with Stock-Based Compensation Awards | (6,515) | | |
| Other | 4,829 | 7,390 | 9,839 |
| Change in: | | | |
| Hedging Collateral Deposits | 58,108 | (69,172) | (7,151) |
| Receivables and Unbilled Utility Revenue | (7,397) | (21,857) | 8,887 |
| Gas Stored Underground and Materials and Supplies | 1,679 | 1,934 | 13,662 |
| Unrecovered Purchased Gas Costs | 1,847 | (7,285) | 21,160 |
| Prepayments and Other Current Assets | (39,572) | (42,409) | 35,647 |
| Accounts Payable | (23,144) | 48,089 | (5,134) |
| Amounts Payable to Customers | 22,777 | (1,996) | 2,462 |
| Other Accruals and Current Liabilities | (17,754) | 18,715 | 2,082 |
| Other Assets | (22,700) | (13,461) | (4,829) |
| Other Liabilities | 80,960 | (3,667) | (34,450) |
| **Net Cash Provided by Operating Activities** | 471,400 | 317,346 | 437,149 |
| **Investing Activities** | | | |
| Capital Expenditures | (294,159) | (219,530) | (172,341) |
| Net Proceeds from Sale of Foreign Subsidiary | | 111,619 | |
| Net Proceeds from Sale of Oil and Gas Producing Properties | 13 | 1,349 | 7,162 |
| Other | (3,230) | 3,238 | 1,974 |
| **Net Cash Used in Investing Activities** | (297,376) | (103,324) | (163,205) |
| **Financing Activities** | | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Change in Notes Payable to Banks and Commercial Paper | | | | (115,359) | | 38,600 |
| Excess Tax Benefits Associated with Stock-Based Compensation Awards | | 6,515 | | | | |
| Shares Repurchased under Repurchase Plan | | (85,168) | | | | |
| Reduction of Long-Term Debt | | (9,805) | | (13,317) | | (243,085) |
| Proceeds from Issuance of Common Stock | | 23,339 | | 20,279 | | 23,763 |
| Dividends Paid on Common Stock | | (98,266) | | (94,159) | | (89,092) |
| Dividends Paid to Minority Interest | | | | (12,676) | | |
| **Net Cash Used in Financing Activities** | | (163,385) | | (215,232) | | (269,814) |
| **Effect of Exchange Rates on Cash** | | 1,365 | | 1,276 | | 3,451 |
| **Net Increase in Cash and Temporary Cash Investments** | | 12,004 | | 66 | | 7,581 |
| **Cash and Temporary Cash Investments At Beginning of Year** | | 57,607 | | 57,541 | | 49,960 |
| **Cash and Temporary Cash Investments At End of Year** | $ | 69,611 | $ | 57,607 | $ | 57,541 |
| **Supplemental Disclosure of Cash Flow Information Cash Paid For:** | | | | | | |
| **Interest** | $ | 78,003 | $ | 84,455 | $ | 90,705 |
| **Income Taxes** | $ | 54,359 | $ | 83,542 | $ | 30,214 |

See Notes to Consolidated Financial Statements

Table of Contents

## NATIONAL FUEL GAS COMPANY

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (Thousands of dollars) | | |
| Net Income Available for Common Stock | $ 138,091 | $ 189,488 | $ 166,586 |
| Other Comprehensive Income (Loss), Before Tax: | | | |
| Minimum Pension Liability Adjustment | 165,914 | (83,379) | 56,612 |
| Foreign Currency Translation Adjustment | 7,408 | 14,286 | 21,466 |
| Reclassification Adjustment for Realized Foreign Currency Translation Gain in Net Income | (716) | (37,793) | |
| Unrealized Gain on Securities Available for Sale Arising During the Period | 2,573 | 2,891 | 3,629 |
| Reclassification Adjustment for Realized Gains On Securities Available for Sale in Net Income | | (651) | |
| Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period | 90,196 | (206,847) | (129,934) |
| Reclassification Adjustment for Realized Loss on Derivative Financial Instruments in Net Income | 91,743 | 97,689 | 49,142 |
| Other Comprehensive Income (Loss), Before Tax: | 357,118 | (213,804) | 915 |
| Income Tax Expense (Benefit) Related to Minimum Pension Liability Adjustment | 58,070 | (29,183) | 19,814 |
| Income Tax Expense Related to Foreign Currency Translation Adjustment | | 112 | |
| Reclassification Adjustment for Income Tax Expense on Foreign Currency Translation Adjustment in Net Income | | (112) | |
| Income Tax Expense Related to Unrealized Gain on Securities Available for Sale Arising During the Period | 894 | 1,012 | 1,270 |
| Reclassification Adjustment for Income Tax Expense on Realized Gains from Securities Available for Sale in Net Income | | (228) | |
| Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period | 34,772 | (79,059) | (49,113) |
| Reclassification Adjustment for Income Tax Benefit on Realized Loss on Derivative Financial Instruments In Net Income | 35,338 | 36,507 | 18,182 |
| Income Taxes Net | 129,074 | (70,951) | (9,847) |
| Other Comprehensive Income (Loss) | 228,044 | (142,853) | 10,762 |
| Comprehensive Income | $ 366,135 | $ 46,635 | $ 177,348 |

See Notes to Consolidated Financial Statements

Table of Contents

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

***Reclassification***

Certain prior year amounts have been reclassified to conform with current year presentation.

***Regulation***

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

***Revenues***

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 Pipeline and Storage and Energy Marketing segments record revenue as bills are rendered for service supplied on a calendar month basis. The Company s Timber segment records revenue on lumber and log sales as products are shipped.

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.

***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.

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

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 more than 2.2% warmer than normal results in a surcharge being added to customers current bills, while weather that is more than 2.2% 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.

Oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. All costs directly associated with property acquisition, exploration and development activities are capitalized, up to certain specified limits. If capitalized costs exceed these limits at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. 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.

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.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***Depreciation, Depletion and Amortization***

For oil and gas properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unevaluated 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 | |
|---|---|---|
| | 2006 | 2005 |
| | (Thousands) | |
| Utility | $ 1,493,991 | $ 1,462,527 |
| Pipeline and Storage | 962,831 | 960,066 |
| Exploration and Production | 1,899,777 | 1,665,774 |
| Energy Marketing | 1,123 | 1,108 |
| Timber | 116,281 | 114,352 |
| All Other and Corporate | 33,338 | 29,275 |
| | $ 4,507,341 | $ 4,233,102 |

Average depreciation, depletion and amortization rates are as follows:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| Utility | 2.8% | 2.8% | 2.8% |
| Pipeline and Storage | 4.0% | 4.1% | 4.1% |
| Exploration and Production, per Mcfe(1) | $ 2.00 | $ 1.74 | $ 1.49 |
| Energy Marketing | 4.8% | 7.6% | 8.7% |
| Timber | 5.6% | 6.2% | 6.5% |
| All Other and Corporate | 4.1% | 4.3% | 6.2% |

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note O Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $1.98, $1.72 and $1.47 per Mcfe of production in 2006, 2005 and 2004, respectively.

***Goodwill***

The Company has recognized goodwill of $5.5 million as of September 30, 2006 and 2005 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, 2006 and 2005, 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.

**NATIONAL FUEL GAS COMPANY**

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

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, no cost collars, options 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. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statements of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2006 or 2004. 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. At September 30, 2005, it was determined that certain derivative financial instruments no longer qualified as effective cash flow hedges due to anticipated delays in oil and gas production volumes caused by Hurricane Rita. These volumes were originally forecast to be produced in the first quarter of 2006. As such, at September 30, 2005, the Company reclassified $5.1 million in accumulated losses on such derivative financial instruments from accumulated other comprehensive income (loss) on the Consolidated Balance Sheet to other revenues on the Consolidated Statement of Income. 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 2006, 2005 or 2004.

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

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

| | Year Ended September 30 2006 | Year Ended September 30 2005 |
|---|---|---|
| | (Thousands) | |
| Minimum Pension Liability Adjustment | $ | $ (107,844) |
| Cumulative Foreign Currency Translation Adjustment | 34,701 | 28,009 |
| Net Unrealized Loss on Derivative Financial Instruments | (11,510) | (123,339) |
| Net Unrealized Gain on Securities Available for Sale | 7,225 | 5,546 |
| Accumulated Other Comprehensive Income (Loss) | $ 30,416 | $ (197,628) |

At September 30, 2006, it is estimated that of the $11.5 million net unrealized loss on derivative financial instruments shown in the table above $12.7 million will be reclassified into the Consolidated Statement of Income during 2007. The remaining unrealized gain on derivative financial instruments of $1.2 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.

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

***Gas Stored Underground Current***

In the Utility segment, gas stored underground current in the amount of $29.5 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 2006, 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 $136.0 million at September 30, 2006. 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.

***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 a consistent 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 2006 | 2005 |
|---|---|---|
| | (Thousands) | |
| Materials and Supplies | $ 13,174 | $ 10,610 |
| Other Assets | 3,218 | 11,510 |
| | $ 16,392 | $ 22,120 |

***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).

***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.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***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.

***Other Current Assets***

Other Current Assets consist of prepayments in the amounts of $25.7 million and $23.9 million at September 30, 2006 and 2005, respectively, federal income taxes receivable in the amounts of $7.5 million and $27.1 million at September 30, 2006 and 2005, respectively, state income taxes receivable in the amounts of $7.4 million and $2.6 million at September 30, 2006 and 2005, respectively, and fair values of firm commitments in the amounts of $23.1 million and $13.7 million at September 30, 2006 and 2005, 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. The only potentially dilutive securities the Company has outstanding are stock options. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflect the potential dilution as a result of these stock options as determined using the Treasury Stock Method. Stock options that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2006, 119,241 stock options were excluded as being antidilutive. There were no stock options excluded as being antidilutive for 2005. For 2004, 2,296,828 stock options were excluded as being antidilutive.

***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, restricted stock, performance units or performance shares. Stock options 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 is exercisable less than one year or more than ten years after the date of each grant. Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. 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.

Table of Contents

## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. The Company has chosen to use the modified version of prospective application, as allowed by SFAS 123R. Using the modified prospective application, the Company is recording compensation cost for the portion of awards granted prior to October 1, 2005 for which the requisite service had not been rendered and is recognizing such compensation cost as the requisite service is 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 317,000, 700,000 and 87,000 stock-based compensation awards granted during the years ended September 30, 2006, 2005 and 2004, respectively. Stock-based compensation expense for the years ended September 30, 2006, September 30, 2005, and September 30, 2004 was approximately $1,705,000 ($442,000 of which relates to the application of the non-substantive vesting period approach discussed below), $517,000 and $835,000, 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, 2006, 2005 and 2004 was approximately $653,000, $206,000 and $333,000, respectively. There were no capitalized stock-based compensation costs during the years ended September 30, 2006 and September 30, 2005.

Prior to the adoption of SFAS 123R, the Company followed the nominal vesting period approach under the disclosure requirements of SFAS 123 for determining the vesting period for awards with retirement-eligible provisions, which recognized stock-based compensation expense over the nominal vesting period. As a result of the adoption of SFAS 123R, the Company currently applies the non-substantive vesting period approach for determining the vesting period of such awards. Under this approach, the retention of the award is not contingent on providing subsequent service and the vesting period would begin at the grant date and end at the retirement-eligible date. For the year ended September 30, 2006, the Company recognized an additional $442,000 ($288,000 net of tax) of stock-based compensation expense by applying the non-substantive vesting approach. For the year ended September 30, 2005, stock-based compensation expense would have been $4,282,000 ($2,752,000 net of tax) for pro forma recognition purposes had the non-substantive vesting period approach been used. The pro forma stock-based compensation expense would have been $2,670,000 ($1,798,000 net of tax) under the non-substantive vesting period approach for the year ended September 30, 2004. Pro forma stock-based compensation expense following the nominal vesting period approach is shown in the table below.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The following table illustrates the effect on net income and earnings per share of the Company had the Company applied the fair value recognition provisions of SFAS 123 relating to stock-based employee compensation for the years ended September 30, 2005 and 2004:

| | Year Ended September 30 2005 | 2004 |
|---|---|---|
| | (Thousands, except per share amounts) | |
| Net Income, Available for Common Stock, As Reported | $ 189,488 | $ 166,586 |
| Add: Stock-Based Employee Compensation Expense Included in Reported Net Income, Net of Tax(1) | 336 | 543 |
| Deduct: Total Stock-Based Employee Compensation Expense Determined Under Fair Value Based Methods for all Awards, Net of Related Tax Effects | (2,782) | (1,861) |
| Pro Forma Net Income Available for Common Stock | $ 187,042 | $ 165,268 |
| Earnings Per Common Share: | | |
| Basic As Reported | $ 2.27 | $ 2.03 |
| Basic Pro Forma | $ 2.24 | $ 2.01 |
| Diluted As Reported | $ 2.23 | $ 2.01 |
| Diluted Pro Forma | $ 2.20 | $ 1.99 |

(1) Stock-based compensation expense in 2005 and 2004 represented compensation expense related to restricted stock awards. The pre-tax expense was $517,000 and $835,000, respectively, for the years ended September 30, 2005 and 2004.

***Stock Options***

The total intrinsic value of stock options exercised during the years ended September 30, 2006, September 30, 2005, and September 30, 2004 totaled approximately $30.9 million, $19.8 million, and $12.4 million, respectively. For 2006, 2005 and 2004, the amount of cash received by the Company from the exercise of such stock options was approximately $30.1 million, $24.8 million, and $16.4 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, 2005, December 31, 2004, and December 31, 2003, the Company realized a tax benefit of $0.9 million, $1.1 million, and $0.1 million, respectively. For stock options exercised during the period of January 1, 2006 through September 30, 2006, the Company will realize a tax benefit of approximately $11.4 million in the quarter ended December 31, 2006. For stock options exercised during the period of January 1, 2005 through September 30, 2005, the Company realized a tax benefit of approximately $6.3 million in the quarter ended December 31, 2005. For stock options exercised during the period of January 1, 2004 through September 30, 2004, the Company realized a tax benefit of approximately $4.8 million in the quarter ended December 31, 2004. The weighted average grant date fair value of options granted in 2006, 2005 and 2004 is

$6.68 per share, $4.59 per share, and $4.66 per share, respectively. For the years ended September 30, 2006, 2005 and 2004, 89,665, 1,375,105 and 729,156 stock options became fully vested, respectively. The total fair value of these stock options was approximately $0.4 million, $6.2 million and $3.3 million, respectively, for the years ended September 30, 2006, 2005 and 2004. As of September 30, 2006, unrecognized compensation expense related to stock options totaled approximately $0.9 million, which will be recognized over a weighted average period of one year. For a summary of transactions during 2006 involving option shares for all plans, refer to Note E    Capitalization and Short-Term Borrowings.

Table of Contents

## NATIONAL FUEL GAS COMPANY

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| Risk Free Interest Rate | 5.08% | 4.46% | 4.61% |
| Expected Life (Years) | 7.0 | 7.0 | 7.0 |
| Expected Volatility | 17.71% | 17.76% | 21.77% |
| Expected Dividend Yield (Quarterly) | 0.83% | 1.00% | 1.12% |

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 prior to October 1, 2005, the Company used a forfeiture rate of 13.6% for calculating stock-based compensation expense related to stock options and this rate is based on the Company s historical experience of forfeitures on unvested stock option grants. For grants during the year ended September 30, 2006, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

***Restricted Share Awards***

For a summary of transactions during 2006 involving restricted share awards, refer to Note E Capitalization and Short-Term Borrowings.

As of September 30, 2006, unrecognized compensation expense related to restricted share awards totaled approximately $577,000, which will be recognized over a weighted average period of 2.1 years.

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 March 2005, the FASB issued 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, a company must record a liability for a conditional asset retirement obligation if the fair value of the obligation can be reasonably estimated. 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. The Company has adopted FIN 47 as of September 30, 2006. Refer to Note B Asset Retirement Obligations for further disclosure regarding the impact of FIN 47 on the Company s consolidated financial statements.

In May 2005, the FASB issued SFAS 154. SFAS 154 replaces APB 20 and SFAS 3 and changes the requirements for the accounting for and reporting of a change in accounting principle. The Company is required to adopt SFAS 154 for accounting changes and corrections of errors that occur in 2007. The Company s financial condition and results of operations will only be impacted by SFAS 154 if there are any accounting changes or corrections of errors in the future.

**NATIONAL FUEL GAS COMPANY**

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

In June 2006, the FASB issued FIN 48, an interpretation of SFAS 109. FIN 48 clarifies the accounting for uncertainty in income taxes and reduces the diversity in current practice associated with the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return by defining a more-likely-than-not threshold regarding the sustainability of the position. The Company is required to adopt FIN 48 by the first quarter of fiscal 2008. The Company is currently evaluating the impact of FIN 48 on its consolidated financial statements.

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. The pronouncement is effective as of the Company s first quarter of fiscal 2009. The Company is currently evaluating the impact that the adoption of SFAS 157 will have 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. The Company is required to recognize the funded status of its benefit plans and the disclosure requirements of SFAS 158 by the fourth quarter of fiscal 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. If the Company recognized the funded status of its pension and post-retirement benefit plans at September 30, 2006, the Company s consolidated balance sheet would reflect a liability of $220.8 million instead of the prepaid pension and post-retirement costs of $64.1 million and pension and post-retirement liabilities of $32.9 million that are currently presented on the balance sheet at September 30, 2006. The Company expects that it will record a regulatory asset for the majority of this liability with the remainder reflected in accumulated other comprehensive income (loss).

**Note B Asset Retirement Obligations**

Effective October 1, 2002, the Company adopted 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. Upon the adoption of SFAS 143, 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.

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.

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

As a result of the adoption of FIN 47, the Company identified 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.

A reconciliation of the Company s asset retirement obligation calculated in accordance with SFAS 143 is shown below ($000s):

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Thousands) | |
| Balance at Beginning of Year | $ 41,411 | $ 32,292 | $ 27,493 |
| Additions Adoption of FIN 47 | 23,234 | | |
| Liabilities Incurred and Revisions of Estimates | 11,244 | 8,343 | 3,510 |
| Liabilities Settled | (1,303) | (1,938) | (831) |
| Accretion Expense | 2,671 | 2,448 | 1,933 |
| Exchange Rate Impact | 135 | 266 | 187 |
| Balance at End of Year | $ 77,392 | $ 41,411 | $ 32,292 |

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, 2006 and 2005, the costs of removal reclassified to other regulatory liabilities amounted to $85.1 million and $90.4 million, respectively.

Pursuant to FIN 47, the financial statements for periods prior to September 30, 2006 have not been restated. If FIN 47 had been in effect, the Company would have recorded additional asset retirement obligations of $21.9 million at September 30, 2005, and $20.6 million at October 1, 2004.

Table of Contents

**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 | |
|---|---|---|
| | 2006 | 2005 |
| | (Thousands) | |
| **Regulatory Assets(1):** | | |
| Recoverable Future Taxes (Note D) | $ 79,511 | $ 85,000 |
| Pension and Post-Retirement Benefit Costs(2) (Note G) | 47,368 | 27,135 |
| Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A) | 12,970 | 14,817 |
| Environmental Site Remediation Costs(2) (Note H) | 12,937 | 13,054 |
| Asset Retirement Obligation(2) (Note B) | 9,018 | |
| Unamortized Debt Expense (Note A) | 8,399 | 9,088 |
| Other(2) | 7,594 | 6,839 |
| Total Regulatory Assets | 177,797 | 155,933 |
| **Regulatory Liabilities**: | | |
| Cost of Removal Regulatory Liability (Note B) | 85,076 | 90,396 |
| New York Rate Settlements(3) | 40,881 | 53,205 |
| Amounts Payable to Customers (See Regulatory Mechanisms in Note A) | 23,935 | 1,158 |
| Tax Benefit on Medicare Part D Subsidy(3) | 13,791 | |
| Pension and Post-Retirement Benefit Costs(3) (Note G) | 13,063 | 12,751 |
| Taxes Refundable to Customers (Note D) | 10,426 | 11,009 |
| Deferred Insurance Proceeds(3) | 7,516 | |
| Other(3) | 205 | 383 |
| Total Regulatory Liabilities | 194,893 | 168,902 |
| Net Regulatory Position | $ (17,096) | $ (12,969) |

(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, 2006 and 2005 of $19.8 million and $34.3 million, respectively. Under the terms of its 2005 rate settlement, Distribution Corporation will pass back that regulatory liability to rate payers over a twenty-four month period that began 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 is principally the accumulation of certain refunds from upstream pipeline companies. During 2005, under the terms of the 2005 rate settlement, 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, 2006 and 2005 amounted to $7.6 million and $7.0 million, respectively.

Other The 2005 settlement also established a reserve to fund area development projects. The balance in the area development projects reserve at September 30, 2006 and 2005 amounted to $3.9 million and $3.8 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 $9.6 million and $8.1 million at September 30, 2006 and 2005, 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 rate payer funds the Company s post-retirement benefit plans. As such, any tax benefit received under the Act must be flowed-through to the rate payer. 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, received $7.5 million in environmental insurance settlement proceeds. 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 rate payers funded the premiums on the former insurance policies.

Table of Contents

**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 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Thousands) | |
| Operating Expenses: | | | |
| Current Income Taxes | | | |
| Federal | $ 65,593 | $ 40,062 | $ 42,679 |
| State | 13,511 | 14,413 | 7,871 |
| Foreign | 2,212 | 1,503 | 206 |
| Deferred Income Taxes | | | |
| Federal | 19,111 | 27,412 | 29,559 |
| State | 9,024 | 2,280 | 9,620 |
| Foreign | (33,365) | 7,308 | 4,655 |
| | 76,086 | 92,978 | 94,590 |
| Other Income: | | | |
| Deferred Investment Tax Credit | (697) | (697) | (697) |
| Discontinued Operations | | | |
| Operations | | 9,310 | (1,479) |
| Gain on Sale | | 1,612 | |
| Total Income Taxes | $ 75,389 | $ 103,203 | $ 92,414 |

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Thousands) | |
| U.S. | $ 293,887 | $ 223,113 | $ 232,928 |
| Foreign | (80,407) | 69,578 | 26,072 |
| | $ 213,480 | $ 292,691 | $ 259,000 |

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 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Thousands) | |
| Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35% | $ 74,718 | $ 102,442 | $ 90,650 |
| Increase in Taxes Resulting from: | | | |
| State Income Taxes | 14,648 | 10,850 | 11,369 |
| Foreign Tax Differential | (3,718) | (4,845) | (1,166) |
| Foreign Tax Rate Reduction | | | (5,174) |
| Reversal of Capital Loss Valuation Allowance | (2,877) | | |
| Miscellaneous | (7,382) | (5,244) | (3,265) |
| Total Income Taxes | $ 75,389 | $ 103,203 | $ 92,414 |

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

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 and the amount for 2005 includes tax effects relating to the disposition of a foreign subsidiary. The foreign tax rate reduction amount shown above for 2004 relates to the reduction of the statutory income tax rate in the Czech Republic. 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 2006 | At September 30 2005 |
|---|---|---|
| | (Thousands) | |
| Deferred Tax Liabilities: | | |
| Property, Plant and Equipment | $ 569,677 | $ 567,850 |
| Other | 37,865 | 52,436 |
| Total Deferred Tax Liabilities | 607,542 | 620,286 |
| Deferred Tax Assets: | | |
| Minimum Pension Liability Adjustment | | (58,069) |
| Capital Loss Carryover | (8,786) | (9,145) |
| Unrealized Hedging Losses | (4,653) | (75,657) |
| Other | (82,006) | (74,346) |
| | (95,445) | (217,217) |
| Valuation Allowance | | 2,877 |
| Total Deferred Tax Assets | (95,445) | (214,340) |
| Total Net Deferred Income Taxes | $ 512,097 | $ 405,946 |
| Presented as Follows: | | |
| Net Deferred Tax Asset Current | $ (23,402) | $ (83,774) |
| Net Deferred Tax Asset Non-Current | (9,003) | |
| Net Deferred Tax Liability Non-Current | 544,502 | 489,720 |
| Total Net Deferred Income Taxes | $ 512,097 | $ 405,946 |

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 $10.4 million and $11.0 million at September 30, 2006 and 2005, 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 $79.5 million and $85.0 million at September 30, 2006 and 2005, respectively.

The American Jobs Creation Act of 2004, signed into law on October 22, 2004, included a provision which provided a substantially reduced tax rate of 5.25% on certain dividends received from foreign affiliates. During 2005, the Company received a dividend of $72.8 million from a foreign affiliate and recorded a tax of $3.8 million on such dividend.

A capital loss carryover of $25.1 million exists at September 30, 2006, which expires if not utilized by September 30, 2008. Although realization is not assured, management determined that it is more likely than not that the entire deferred tax asset associated with this carryover will be realized during the carryover period. As such, the valuation allowance of $2.9 million was reversed during 2006.

**NATIONAL FUEL GAS COMPANY**

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

A deferred tax asset of $9.0 million relating to Canadian operations exists at September 30, 2006. Although realization is not assured, management determined that it is more likely than not that future taxable income will be generated in Canada to fully utilize this asset, and as such, no valuation allowance was provided.

## 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, 2003 | 81,438 | $ 81,438 | $ 478,799 | $ 642,690 | $ (65,537) |
| Net Income Available for Common Stock | | | | 166,586 | |
| Dividends Declared on Common Stock ($1.10 Per Share) | | | | (90,350) | |
| Other Comprehensive Income, Net of Tax | | | | | 10,762 |
| Common Stock Issued Under Stock and Benefit Plans(1) | 1,552 | 1,552 | 27,761 | | |
| Balance at September 30, 2004 | 82,990 | 82,990 | 506,560 | 718,926 | (54,775) |
| Net Income Available for Common Stock | | | | 189,488 | |
| Dividends Declared on Common Stock ($1.14 Per Share) | | | | (95,394) | |
| Other Comprehensive Loss, Net of Tax | | | | | (142,853) |
| Cancellation of Shares | (2) | (2) | (52) | | |
| Common Stock Issued Under Stock and Benefit Plans(1) | 1,369 | 1,369 | 23,326 | | |
| 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(3) | $ 30,416 |

(1) Paid in Capital includes tax benefits of $6.5 million, $3.7 million and $1.5 million for September 30, 2006, 2005 and 2004, respectively, associated with the exercise of stock options.

(2) As of October 1, 2005, Paid in Capital includes compensation costs associated with stock option and 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, 2006, $692.7 million of accumulated earnings was free of such limitations.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

***Common Stock***

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

During 2006, the Company issued 2,292,639 original issue shares of common stock as a result of stock option exercises and 16,000 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 2006, 744,567 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 the Company common stock to its non-employee directors as partial consideration for their services as directors. Under this program, the Company issued 8,400 original issue shares of common stock to the non-employee directors of the Company during 2006.

On December 8, 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 8 million shares in the open market or through privately negotiated transactions. During 2006, the Company repurchased 2,526,550 shares under this program, funded with cash provided by operating activities. At September 30, 2006, the Company had made commitments to repurchase an additional 99,100 shares of common stock. These commitments were settled and recorded as a reduction of the Company s outstanding shares of common stock in October 2006.

***Shareholder Rights Plan***

In 1996, the Company s Board of Directors adopted a shareholder rights plan (Plan). Effective April 30, 1999, the Plan was amended and is now embodied in an Amended and Restated Rights Agreement, under which the Board of Directors made adjustments in connection with the two-for-one stock split of September 7, 2001.

The holders of the Company s common stock have one right (Right) for each of their shares. Each Right, which will initially be evidenced by the Company s common stock certificates representing the outstanding shares of common stock, entitles the holder to purchase one-half of one share of common stock at a purchase price of $65.00 per share, being $32.50 per half share, subject to adjustment (Purchase Price).

The Rights become exercisable upon the occurrence of a distribution date. At any time following a distribution date, each holder of a Right may exercise its right to receive common stock (or, under certain circumstances, other property of the Company) having a value equal to two times the Purchase Price of the Right then in effect. 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 having 10% or more of the total voting power of the Company s common stock and other

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 common stock of the acquiring company having a value equal to two times the Purchase Price of the Right then in effect. 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 announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of 10% or more of the total voting power of the Company, 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 announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of 10% or more of the total voting power of the Company, 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.

After a distribution date, Rights that are owned by an acquiring person will be null and void. 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, 2008, unless they are exchanged or redeemed earlier than that date.

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

***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, restricted stock, performance units or performance shares. Stock options 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 is exercisable less than one year or more than ten years after the date of each grant.

Table of Contents

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, 2005 | 10,996,893 | $ 23.78 | | |
| Granted in 2006 | 317,000 | $ 35.21 | | |
| Exercised in 2006 | (2,292,639) | $ 21.77 | | |
| Forfeited in 2006 | (5,000) | $ 24.94 | | |
| Outstanding at September 30, 2006 | 9,016,254 | $ 24.69 | 4.21 | $ 105,096 |
| Option shares exercisable at September 30, 2006 | 8,643,753 | $ 24.32 | 4.01 | $ 103,999 |
| Option shares available for future grant at September 30, 2006(1) | 434,911 | | | |

(1) Including shares available for restricted stock grants.

The following table summarizes information about options outstanding at September 30, 2006:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Price | Number Outstanding at 9/30/06 | Weighted Average Remaining Contractual Life | Weighted Average Exercise Price | Number Exercisable at 9/30/06 | Weighted Average Exercise Price |
| $18.55-$22.26 | 1,598,641 | 3.3 | $ 21.31 | 1,568,641 | $ 21.32 |
| $22.27-$25.97 | 4,500,219 | 3.5 | $ 23.33 | 4,480,718 | $ 23.32 |
| $25.98-$29.68 | 2,600,394 | 5.3 | $ 27.85 | 2,594,394 | $ 27.85 |
| $29.69-$33.39 | | | | | |
| $33.40-$37.10 | 317,000 | 9.6 | $ 35.21 | | |

***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.

**Table of Contents**

**NATIONAL FUEL GAS COMPANY**

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

Transactions involving option 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, 2005 | 64,928 | $ | 24.46 |
| Granted in 2006 | 16,000 | $ | 34.94 |
| Vested in 2006 | (38,600) | $ | 24.43 |
| Restricted Share Awards Outstanding at September 30, 2006 | 42,328 | $ | 28.44 |

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2006 will lapse as follows: 2007 25,000 shares; 2008 2,500 shares; 2009 4,500 shares; 2010 5,828 shares; and 2011 4,500 shares.

***Redeemable Preferred Stock***

As of September 30, 2006, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

***Long-Term Debt***

The outstanding long-term debt is as follows:

| | At September 30 2006 | | 2005 | |
|---|---|---|---|---|
| | (Thousands) | | | |
| Medium-Term Notes(1): | | | | |
| 6.0% to 7.50% due May 2008 to June 2025 | $ | 749,000 | $ | 749,000 |
| Notes(1): | | | | |
| 5.25% to 6.50% due March 2013 to September 2022(2) | | 346,665 | | 347,222 |
| | | 1,095,665 | | 1,096,222 |
| Other Notes: | | | | |
| Secured(3) | | 22,766 | | 32,100 |
| Unsecured | | 169 | | 83 |
| Total Long-Term Debt | | 1,118,600 | | 1,128,405 |
| Less Current Portion | | 22,925 | | 9,393 |

| | | |
|---|---|---|
| | $ 1,095,675 | $ 1,119,012 |

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

(2) At September 30, 2006 and 2005, $96,665,000 and $97,222,000, respectively, of these notes were callable at par at any time after September 15, 2006. The change in the amount outstanding from year to year is attributable to the estates of individual note holders exercising put options due to the death of an individual note holder.

(3) These notes constitute project financing and are secured by the various project documentation and natural gas transportation contracts related to the Empire State Pipeline. The interest rate on these notes is a variable rate based on LIBOR. It is the Company s intention to pay off these notes within one year. As such, the notes have been classified as current.

**NATIONAL FUEL GAS COMPANY**

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

As of September 30, 2006, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $22.9 million in 2007, $200.0 million in 2008, $100.0 million in 2009, zero in 2010, $200.0 million in 2011, and $595.7 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 (bi-lateral) 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 $445.0 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, which is committed to the Company through September 30, 2010.

At September 30, 2006 and September 30, 2005, the Company had no outstanding short-term notes payable to banks or commercial paper.

***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 from September 30, 2005 through September 30, 2010. At September 30, 2006, the Company s debt to capitalization ratio (as calculated under the facility) was .44. The constraints specified in the committed credit facility would permit an additional $1.56 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 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, 2006, the Company would have been permitted to issue up to a maximum of $1.03 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 $399.0 million (or 36%) of the Company s long-term debt (as of September 30, 2006) 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 fails 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

Table of Contents

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2006, 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 | | | |
|---|---|---|---|---|
| | 2006 Carrying Amount | 2006 Fair Value | 2005 Carrying Amount | 2005 Fair Value |
| | (Thousands) | | | |
| Long-Term Debt | $ 1,118,600 | $ 1,148,089 | $ 1,128,405 | $ 1,181,599 |

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 insurance are stated at their cash surrender values 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 includes cash surrender values of insurance contracts and marketable equity securities. The cash surrender values of the insurance contracts amounted to $62.5 million and $59.6 million at September 30, 2006 and 2005, respectively. The fair value of the equity mutual fund was $12.9 million and $9.8 million at September 30, 2006 and September 30, 2005, respectively. The gross unrealized gain on this equity mutual fund was $1.0 million and $0.4 million at September 30, 2006 and September 30, 2005, respectively. During 2005, the Company sold all of its interest in one equity mutual fund for $8.5 million and reinvested the proceeds in another equity mutual fund. The Company recognized a gain of $0.7 million on the sale of the equity mutual fund. The fair value of the stock of an insurance company was $12.7 million and $10.5 million at September 30, 2006 and 2005, respectively. The gross unrealized gain on this stock was $10.3 million and $8.1 million at September 30, 2006 and 2005, 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, options 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 Inside FERC. 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

**NATIONAL FUEL GAS COMPANY**

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

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, 2006, the Company had natural gas price swap agreements covering a notional amount of 7.4 Bcf extending through 2009 at a weighted average fixed rate of $7.24 per Mcf. Of this amount, 1.1 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $6.98 per Mcf. The remaining 6.3 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $7.29 per Mcf. At September 30, 2006, the Company would have had to pay a net $7.4 million to terminate the price swap agreements. The Company also had crude oil price swap agreements covering a notional amount of 900,000 bbls extending through 2008 at a weighted average fixed rate of $37.13 per bbl. At September 30, 2006, the Company would have had to pay a net $27.6 million to terminate the price swap agreements.

Under the no cost collars, the Company receives monthly payments from (or makes payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). The variable price is either a crude oil price quoted on the NYMEX or a quoted natural gas price in Inside FERC. These derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price range for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment. At September 30, 2006, the Company had no cost collars on natural gas covering a notional amount of 7.1 Bcf extending through 2008 with a weighted average floor price of $8.26 per Mcf and a weighted average ceiling price of $17.25 per Mcf. At September 30, 2006, the Company would have received $10.4 million to terminate the no cost collars. At September 30, 2006, the Company had no cost collars on crude oil covering a notional amount of 180,000 bbls extending through 2007 with a weighted average floor price of $70.00 per bbl and a weighted average ceiling price of $77.00 per bbl. At September 30, 2006, the Company would have received $0.9 million to terminate these no cost collars.

At September 30, 2006, the Company had long (purchased) futures contracts covering 14.5 Bcf of gas extending through 2012 at a weighted average contract price of $9.20 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 commercial and industrial customers. The Company would have had to pay $22.4 million to terminate these futures contracts at September 30, 2006.

At September 30, 2006, the Company had short (sold) futures contracts covering 7.5 Bcf of gas extending through 2009 at a weighted average contract price of $10.57 per Mcf. Of this amount, 4.7 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Energy Marketing segment. The remaining 2.8 Bcf is accounted for as fair value hedges. The Company would have received $17.5 million to terminate these futures contracts at September 30, 2006.

The Company may be exposed to credit risk on some of the derivative financial instruments discussed 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 the parent companies of the respective counterparties to its derivative financial instruments. At September 30, 2006, the Company used six counterparties for its over the counter derivative financial instruments. At September 30, 2006, no individual counterparty represented greater than 39% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company s total volumes hedged). All of the counterparties (or the parent of the counterparty) were rated as investment grade entities at September 30, 2006.

The Company uses an interest rate collar to limit interest rate fluctuations on certain variable rate debt in the Pipeline and Storage segment. Under the interest rate collar the Company makes quarterly payments to (or receives payments from) another party when a variable rate falls below an established floor rate (the Company

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

pays the counterparty) or exceeds an established ceiling rate (the Company receives payment from the counterparty). Under the terms of the collar, which extends until 2009, the variable rate is based on LIBOR. The floor rate of the collar is 5.15% and the ceiling rate is 9.375%. At September 30, 2006 the notional amount on the collar was $25.7 million. The Company would have had to pay $0.1 million to terminate the interest rate collar at September 30, 2006.

## 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 77% of the domestic employees of the Company. The Company provides health care and life insurance benefits for substantially all domestic retired employees under a post-retirement benefit plan (Post-Retirement Plan).

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 Post-Retirement Plan. 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 post-retirement health care and life insurance benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its Post-Retirement Plan. They are separate accounts within the Retirement Plan used to pay retiree medical benefits for the associated participants in the Retirement Plan. Contributions are tax-deductible when made and investments accumulate tax-free. Retirement Plan and Post-Retirement Plan assets primarily consist of equity and fixed income investments or units in commingled funds or money market funds.

The expected returns on plan assets of the Retirement Plan and Post-Retirement Plan are applied to the market-related value of plan assets of the respective plans. The market-related values of the Retirement Plan and Post-Retirement Plan assets are 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 Post-Retirement Plan are shown in the tables below. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is June 30, 2006, 2005 and 2004, respectively.

| | Retirement Plan Year Ended September 30 | | | Other Post-Retirement Benefits Year Ended September 30 | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| | (Thousands) | | | | | |
| **Change in Benefit Obligation** | | | | | | |
| Benefit Obligation at Beginning of Period | $ 825,204 | $ 693,532 | $ 694,960 | $ 546,273 | $ 422,003 | $ 467,418 |
| Service Cost | 16,416 | 13,714 | 14,598 | 8,029 | 6,153 | 6,027 |
| Interest Cost | 40,196 | 42,079 | 40,565 | 26,804 | 25,783 | 26,393 |
| Plan Participants Contributions | | | | 1,559 | 1,017 | 627 |
| Actuarial (Gain) Loss | (108,112) | 115,128 | (19,593) | (115,052) | 110,663 | (62,146) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Benefits Paid | (41,497) | (39,249) | (36,998) | (21,682) | (19,346) | (16,316) |
| **Benefit Obligation at End of Period** | $ 732,207 | $ 825,204 | $ 693,532 | $ 445,931 | $ 546,273 | $ 422,003 |

**NATIONAL FUEL GAS COMPANY**

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

| | Retirement Plan Year Ended September 30 | | | Other Post-Retirement Benefits Year Ended September 30 | | |
|---|---|---|---|---|---|---|
| | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| | (Thousands) | | | | | |
| **Change in Plan Assets** | | | | | | |
| Fair Value of Assets at Beginning of Period | $ 616,462 | $ 573,366 | $ 491,333 | $ 271,636 | $ 229,485 | $ 166,494 |
| Actual Return on Plan Assets | 68,649 | 56,201 | 81,946 | 34,785 | 20,577 | 38,960 |
| Employer Contribution | 20,907 | 26,144 | 37,085 | 39,326 | 39,903 | 39,720 |
| Plan Participants Contributions | | | | 1,559 | 1,017 | 627 |
| Benefits Paid | (41,497) | (39,249) | (36,998) | (21,682) | (19,346) | (16,316) |
| **Fair Value of Assets at End of Period** | $ 664,521 | $ 616,462 | $ 573,366 | $ 325,624 | $ 271,636 | $ 229,485 |
| **Reconciliation of Funded Status** | | | | | | |
| Funded Status | $ (67,686) | $ (208,742) | $ (120,166) | $ (120,307) | $ (274,637) | $ (192,518) |
| Unrecognized Net Actuarial Loss | 107,626 | 257,553 | 159,554 | 54,487 | 205,423 | 108,943 |
| Unrecognized Transition Obligation | | | | 49,890 | 57,017 | 64,144 |
| Unrecognized Prior Service Cost | 7,185 | 8,142 | 9,171 | 12 | 17 | 20 |
| Net Amount Recognized at End of Period | $ 47,125 | $ 56,953 | $ 48,559 | $ (15,918) | $ (12,180) | $ (19,411) |
| **Amounts Recognized in the Balance Sheets Consist of:** | | | | | | |
| Accrued Benefit Liability | $ | $ (117,103) | $ (43,147) | $ (32,918) | $ (26,584) | $ (27,263) |
| Prepaid Benefit Cost | 47,125 | | | 17,000 | 14,404 | 7,852 |
| Intangible Assets | | 8,142 | 9,171 | | | |
| Accumulated Other Comprehensive Loss (Pre-Tax) | | 165,914 | 82,535 | | | |
| | $ 47,125 | $ 56,953 | $ 48,559 | $ (15,918) | $ (12,180) | $ (19,411) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Net Amount Recognized at End of Period | | | | | | |
| **Weighted Average Assumptions Used to Determine Benefit Obligation at September 30** | | | | | | |
| Discount Rate | 6.25% | 5.00% | 6.25% | 6.25% | 5.00% | 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 | $ 16,416 | $ 13,714 | $ 14,598 | $ 8,029 | $ 6,153 | $ 6,027 |
| Interest Cost | 40,196 | 42,079 | 40,565 | 26,804 | 25,783 | 26,393 |
| Expected Return on Plan Assets | (49,943) | (49,545) | (48,281) | (22,302) | (18,862) | (14,898) |
| Amortization of Prior Service Cost | 957 | 1,029 | 1,103 | 4 | 4 | 4 |
| Amortization of Transition Amount | | | | 7,127 | 7,127 | 7,127 |
| Recognition of Actuarial Loss | 23,108 | 10,473 | 9,438 | 23,402 | 12,467 | 17,092 |
| Net Amortization and Deferral for Regulatory Purposes | (6,409) | 1,988 | 722 | (11,084) | (410) | (9,731) |
| Net Periodic Benefit Cost | $ 24,325 | $ 19,738 | $ 18,145 | $ 31,980 | $ 32,262 | $ 32,014 |
| Other Comprehensive (Income) Loss (Pre-Tax) Attributable to Change In Additional Minimum Liability Recognition | $ (165,914) | $ 83,379 | $ (56,612) | $ | $ | $ |

**NATIONAL FUEL GAS COMPANY**

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

| | Retirement Plan | | | Other Post-Retirement Benefits | | |
|---|---|---|---|---|---|---|
| | Year Ended September 30 | | | Year Ended September 30 | | |
| | 2006 | 2005 | 2004 | 2006 | 2005 | 2004 |
| | (Thousands) | | | | | |
| **Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30** | | | | | | |
| Discount Rate | 5.00% | 6.25% | 6.00% | 5.00% | 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% |

* The weighted average discount rate was 6.0% through 12/8/2003. Subsequent to 12/8/2003, the discount rate used was 6.25%.

The Net Periodic Benefit cost in the table above includes the effects of regulation. The Company recovers pension and 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 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 post-retirement regulatory assets) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

In accordance with the provisions of SFAS 87, the Company recorded an additional minimum pension liability at September 30, 2005 and 2004 representing the excess of the accumulated benefit obligation over the fair value of plan assets plus accrued amounts previously recorded. An intangible asset, as shown in the table above, 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 at September 30, 2006, 2005 and 2004 are shown in the table above. The projected benefit obligation, accumulated benefit obligation and fair value of assets for the retirement plan were as follows:

| | 2006 | 2005 | 2004 |
|---|---|---|---|
| Projected Benefit Obligation | $ 732,207 | $ 825,204 | $ 693,532 |
| Accumulated Benefit Obligation | $ 660,026 | $ 733,565 | $ 616,513 |
| Fair Value of Plan Assets | $ 664,520 | $ 616,462 | $ 573,366 |

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. The effect of the discount rate change for the Retirement Plan in 2005 was to increase the projected benefit obligation by $113.0 million. The discount rate change for the Retirement Plan in 2004 caused the projected benefit obligation to decrease by $20.2 million.

The Company made cash contributions totaling $20.9 million to the Retirement Plan during the year ended September 30, 2006. The Company expects that the annual contribution to the Retirement Plan in 2007 will be in the range of $15.0 million to $20.0 million. The following benefit payments, which reflect expected future service, are expected to be paid during the next five years and the five years thereafter: $45.2 million in 2007; $46.1 million in 2008; $47.3 million in 2009; $48.7 million in 2010; $50.0 million in 2011; and $275.6 million in the five years thereafter.

**NATIONAL FUEL GAS COMPANY**

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

The Retirement Plan covers certain domestic employees hired before July 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 $0.2 million through September 30, 2006 (with $0.1 million of costs occurring in fiscal 2006). Costs associated with the Company s contributions to the Tax-Deferred Savings Plans were $4.1 million, $4.2 million, and $4.2 million for the years ended September 30, 2006, 2005 and 2004, respectively.

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 $5.4 million, $4.3 million and $13.7 million in 2006, 2005 and 2004, respectively. The accumulated benefit obligation for this plan was $26.5 million and $25.2 million at September 30, 2006 and 2005, respectively. The projected benefit obligation for the plan was $44.5 million and $47.6 million at September 30, 2006 and 2005, respectively. The actuarial valuations for this plan were determined based on a discount rate of 6.25%, 5.0% and 6.25% as of September 30, 2006, 2005 and 2004, respectively; a rate of compensation increase of 10.0% as of September 30, 2006, 2005 and 2004; and an expected long-term rate of return on plan assets of 8.25% at September 30, 2006, 2005 and 2004.

In January 2004, a participant of the Non Qualified benefit plan received a $23 million lump sum payment under a provision of an agreement previously entered into between the Company and the participant. Under GAAP, this payment was considered a partial settlement of the projected benefit obligation of the plan. Accordingly, GAAP required that a pro rata portion of this plan s unrecognized actuarial loses resulting from experience different from that assumed and from changes in assumption be currently recognized. Therefore, $9.9 million before tax ($6.4 million, after tax) was recognized as a settlement expense (included in Operation and Maintenance Expense) on the income statement.

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.

The effect of the discount rate change in 2005 was to increase the other post-retirement benefit obligation by $78.2 million. Effective July 1, 2005, 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 $21.7 million. Also effective July 1, 2005, the percent of active female participants who are assumed to be married at retirement was changed. The effect of this assumption change was to decrease the other post-retirement benefit obligation by $6.9 million. Other actuarial experience increased the other post-retirement benefit obligation in 2005 by $17.9 million.

On December 8, 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. This Act introduces 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. The discount rate was changed from 6.0% to 6.25% per annum as of the remeasurement date, which resulted in a decrease in the benefit obligation of $15.9 million in 2004. The other post-retirement benefit obligation decreased by $42.9 million and the Net Periodic Post-Retirement Benefit Cost

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

decreased by $4.2 million as a result of the Act for 2004. Effective July 1, 2004, the Medicare B Reimbursement trend assumption was changed. The effect of this change was to decrease the other post-retirement benefit obligation by $3.5 million for 2004.

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

| | Benefit Payments | | Subsidy Receipts | |
|---|---|---|---|---|
| First Year | $ | 22,994,788 | $ | (1,475,584) |
| Second Year | $ | 24,993,192 | $ | (1,712,545) |
| Third Year | $ | 26,857,371 | $ | (1,959,704) |
| Fourth Year | $ | 28,913,929 | $ | (2,191,014) |
| Fifth Year | $ | 30,877,647 | $ | (2,413,305) |
| Next Five Years | $ | 175,465,690 | $ | (15,964,373) |

The annual rate of increase in the per capita cost of covered medical care benefits for both Pre and Post age 65 participants was assumed to be 10.0% for 2004. In 2005, the Company began making separate estimates of the annual rate of increase in the per capita cost of covered medical care benefits for Pre and Post age 65 participants. The rate of increase for Pre age 65 participants was assumed to be 10% while the rate of increase for Post age 65 participants was assumed to be 7.5%. In 2006, the rate of increase for Pre age 65 participants was 9% and was assumed to gradually decline to 5.0% by the year 2014. The rate of increase for the Post age 65 participants was 7.0% and was assumed to gradually decline to 5.0% by the year 2014. The annual rate of increase in the per capita cost of covered prescription drug benefits was assumed to be 12.0% for 2004, 12.5% for 2005, 11.0% for 2006, and gradually decline to 5.0% by the year 2014 and remain level thereafter. The annual rate of increase in the per capita Medicare Part B Reimbursement was assumed to be 9.25% for 2004, 6.0% for 2005, and 5.25% for 2006. The annual rate of increase for the Medicare Part B Reimbursement is expected to fluctuate between 0% and 5.0% over the next 10 years and reach 5.0% by 2016.

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, 2006 would be increased by $57.3 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 2006 by $6.1 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, 2006 would be decreased by $47.5 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2006 by $4.9 million.

The Company made cash contributions including payments made directly to participants totaling $39.3 million to the Post-Retirement Plan during the year ended September 30, 2006. The Company expects that the annual contribution to the Post-Retirement Plan in 2006 will be in the range of $35.0 million to $45.0 million.

The Company s Retirement Plan weighted average asset allocations at September 30, 2006, 2005 and 2004 by asset category are as follows:

| Asset Category | Target Allocation 2007 | Percentage of Plan Assets at September 30 2006 | 2005 | 2004 |
|---|---|---|---|---|
| Equity Securities | 60-75% | 67% | 63% | 61% |
| Fixed Income Securities | 20-35% | 26% | 28% | 28% |
| Other | 0-15% | 7% | 9% | 11% |
| Total | | 100% | 100% | 100% |

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

The Company s Post-Retirement Plan weighted average asset allocations at September 30, 2006, 2005 and 2004 by asset category are as follows:

| Asset Category | Target Allocation 2007 | Percentage of Plan Assets at September 30 2006 | 2005 | 2004 |
|---|---|---|---|---|
| Equity Securities | 85-100% | 93% | 92% | 91% |
| Fixed Income Securities | 0-15% | 1% | 2% | 1% |
| Other | 0-15% | 6% | 6% | 8% |
| 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 and the Post-Retirement Plan VEBA trusts 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 Post-Retirement Plan is 6.25% as of September 30, 2006. This rate is equal to the Moody s Aa Long-Term Corporate Bond index, rounded to the nearest 25 basis points. The duration of the securities underlying that index (approximately 13 years) reasonably matches the expected timing of anticipated future benefit payments (approximately 12 years).

## 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. The Company has estimated its remaining clean-up costs related to the sites described below in paragraphs (i) and (ii) will be $3.8 million. This liability has been recorded on the Consolidated Balance Sheet at September 30, 2006. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and insurance proceeds (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, adverse changes in environmental regulations, new information or other factors could impact the Company.

*(i) Former Manufactured Gas Plant Sites*

The Company has incurred or is incurring clean-up costs at five former manufactured gas plant sites in New York and Pennsylvania. The Company continues to be responsible for future ongoing maintenance at one

**NATIONAL FUEL GAS COMPANY**

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

site. At a second site in New York, the Company settled its environmental obligations related to this site during 2005. No future liability is anticipated at this site. At a third site, remediation is complete and long-term maintenance and monitoring activities are ongoing. A fourth site, which allegedly contains, among other things, manufactured gas plant waste, is in the investigation stage. Remediation and post-remedial construction care and maintenance have been completed at a fifth site, and the Company has been released from any future liability related to this site by the Pennsylvania Department of Environmental Protection.

*(ii) Third Party Waste Disposal Sites*

The Company has been identified by the Department of Environmental Conservation (DEC) or the United States Environmental Protection Agency as one of a number of companies considered to be PRPs with respect to two waste disposal sites in New York which were operated by unrelated third parties. The PRPs are alleged to have contributed to the materials that may have been collected at such waste disposal sites by the site operators. The ultimate cost to the Company with respect to the remediation of these sites will depend on such factors as the remediation plan selected, the extent of site contamination, the number of additional PRPs at each site and the portion of responsibility, if any, attributed to the Company. The remediation has been completed at one site, with costs subject to an ongoing final reallocation process among five PRPs. At a second waste disposal site, settlement was reached in the amount of $9.3 million to be allocated among five PRPs. The allocation process is currently being determined. Further negotiations remain in process for additional settlements related to this site.

*(iii) Other*

The Company received, in 1998 and again in October 1999, notice that the DEC believes the Company is responsible for contamination discovered at an additional former manufactured gas plant site in New York. The Company, however, has not been named as a PRP. The Company responded to these notices that other companies operated that site before its predecessor did, that liability could be imposed upon it only if hazardous substances were disposed at the site during a period when the site was operated by its predecessor, and that it was unaware of any such disposal. The Company has not incurred any clean-up costs at this site nor has it been able to reasonably estimate the probability or extent of potential liability.

***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: $793.5 million in 2007, $195.2 million in 2008, $48.9 million in 2009, $17.6 million in 2010, $9.9 million in 2011, and $68.8 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: $8.1 million in 2007, $7.2 million in 2008, $6.0 million in 2009, $4.3 million in 2010, $2.7 million in 2011, and $15.7 million thereafter.

The Company is involved in 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 that involve rate base, cost of service and purchased gas cost issues. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

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

**Note I Discontinued Operations**

On July 18, 2005, the Company completed the sale of its entire 85.16% interest in U.E., a district heating and electric generation business in the Bohemia region of the Czech Republic, to Czech Energy Holdings, a.s. for sales proceeds of approximately $116.3 million. The sale resulted in the recognition of a gain of approximately $25.8 million, net of tax, at September 30, 2005. Market conditions during 2005, including the increasing value of the Czech currency as compared to the U.S. dollar, caused the value of the assets of U.E. to increase, providing an opportunity to sell the U.E. operations at a profit for the Company. As a result of the decision to sell its majority interest in U.E., the Company began presenting the Czech Republic operations, which are primarily comprised of U.E., as discontinued operations in June 2005. U.E. was the major component of the Company s International segment. With this change in presentation, the Company discontinued all reporting for an International segment.

The following is selected financial information of the discontinued operations for U.E.:

| | Year Ended September 30 | |
|---|---|---|
| | **2005** | **2004** |
| | **(Thousands)** | |
| Operating Revenues | $ 124,840 | $ 123,425 |
| Operating Expenses | 103,155 | 112,178 |
| Operating Income | 21,685 | 11,247 |
| Other Income | 2,048 | 1,992 |
| Interest Expense | (558) | (838) |
| Income before Income Taxes and Minority Interest | 23,175 | 12,401 |
| Income Tax Expense | 10,331 | (1,853) |
| Minority Interest, Net of Taxes | 2,645 | 1,933 |
| Income from Discontinued Operations | 10,199 | 12,321 |
| Gain on Disposal, Net of Taxes of $1,612 | 25,774 | |
| Income from Discontinued Operations | $ 35,973 | $ 12,321 |

**Note J Business Segment Information**

The Company has five reportable 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

**NATIONAL FUEL GAS COMPANY**

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

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, in the Gulf Coast region of Texas, Louisiana and Alabama and in the provinces of Alberta, Saskatchewan and British Columbia in Canada. Seneca s production is, for the most part, sold to purchasers located in the vicinity of its wells. On September 30, 2003, Seneca sold its southeast Saskatchewan oil and gas properties for a loss of $58.5 million. Proved reserves associated with the properties sold were 19.4 million barrels of oil and 0.3 Bcf of natural gas. When the transaction closed, the initial proceeds received were subject to an adjustment based on working capital and the resolution of certain income tax matters. In 2004, those items were resolved with the buyer and, as a result, the Company received an additional $4.6 million of sales proceeds, as shown in the table below for the year ended September 30, 2004.

The Energy Marketing segment is comprised of NFR s operations. NFR markets natural gas to industrial, commercial, public authority and residential end-users in western and central New York and northwestern Pennsylvania, offering competitively priced energy and energy management services 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. On August 1, 2003, the Company sold approximately 70,000 acres of timber property in Pennsylvania and New York. A gain of $168.8 million was recognized on the sale of this timber property. During 2004, the Company received final timber cruise information of the properties it sold and, based on that information, determined that property records pertaining to $1.3 million of timber property were not properly shown as having been transferred to the purchaser. As a result, the Company removed those assets from its property records and adjusted the previously recognized gain downward by recognizing a pretax loss of $1.3 million, as shown in the table for the year ended September 30, 2004.

The data presented in the tables below reflect the reportable 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.

As disclosed in Note I Discontinued Operations, the Company completed the sale of its majority interest in U.E., a district heating and electric generation business in the Czech Republic, on July 18, 2005. As a result of the sale of its majority interest in U.E., the Company discontinued all reporting for an International segment and previous period segment information has been restated to reflect this change. All Czech Republic operations have been reported as discontinued operations. Any remaining international activity has been included in corporate operations.

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

| | Year Ended September 30, 2006 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber (Thousands) | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | T Cons |
| from External rs | $ 1,265,695 | $ 132,921 | $ 346,880 | $ 497,069 | $ 65,024 | $ 2,307,589 | $ 3,304 | $ 766 | $ 2, |
| nent Revenues | $ 15,068 | $ 81,431 | $ | $ | $ 5 | $ 96,504 | $ 9,444 | $ (105,948) | $ |
| ncome | $ 4,889 | $ 454 | $ 8,682 | $ 445 | $ 747 | $ 15,217 | $ 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 | $ 94,738 | $ 53 | $ 6,495 | $ 178,334 | $ 789 | $ 492 | $ |
| ax Expense | $ 35,699 | $ 33,896 | $ (2,808) | $ 3,748 | $ 3,277 | $ 73,812 | $ 969 | $ 1,305 | $ |
| rom idated ies | $ | $ | $ | $ | $ | $ | $ 3,583 | $ | $ |
| nt Non-Cash | | | | | | | | | |
| ent of Oil and ucing s | $ | $ | $ 104,739 | $ | $ | $ 104,739 | $ | $ | $ |
| Profit (Loss): me (Loss) | $ 49,815 | $ 55,633 | $ 20,971 | $ 5,798 | $ 5,704 | $ 137,921 | $ 359 | $ (189) | $ |
| ures for s to ed Assets | $ 54,414 | $ 26,023 | $ 208,303 | $ 16 | $ 2,323 | $ 291,079 | $ 85 | $ 2,995 | $ |

| | At September 30, 2006 (Thousands) | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| ent Assets | $ 1,471,422 | $ 767,889 | $ 1,209,969 | $ 78,977 | $ 159,421 | $ 3,687,678 | $ 64,287 | $ (17,634) | $ 3,734 |

| | Year Ended September 30, 2005 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber (Thousands) | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | Con |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| om External | $ 1,101,572 | $ 132,805 | $ 293,425 | $ 329,714 | $ 61,285 | $ 1,918,801 | $ 4,748 | $ | $ |
| nt Revenues | $ 15,495 | $ 83,054 | $ | $ | $ 1 | $ 98,550 | $ 8,606 | $ (107,156) | $ |
| ome | $ 4,111 | $ 76 | $ 4,661 | $ 783 | $ 438 | $ 10,069 | $ 19 | $ (3,592) | $ |
| pense | $ 22,900 | $ 7,128 | $ 48,856 | $ 11 | $ 2,764 | $ 81,659 | $ 1,726 | $ (1,072) | $ |
| on, Depletion zation | $ 40,159 | $ 38,050 | $ 90,912 | $ 41 | $ 6,601 | $ 175,763 | $ 3,537 | $ 467 | $ |
| x Expense | $ 23,102 | $ 39,068 | $ 28,353 | $ 3,210 | $ 2,271 | $ 96,004 | $ (1,425) | $ (1,601) | $ |
| m ated s | $ | $ | $ | $ | $ | $ | $ 3,362 | $ | $ |
| Non-Cash t of in | $ | $ | $ | $ | $ | $ | $ (4,158)(1) | $ | $ |
| ofit (Loss): oss) from Operations | $ 39,197 | $ 60,454 | $ 50,659 | $ 5,077 | $ 5,032 | $ 160,419 | $ (2,616) | $ (4,288) | $ |
| es for o d Assets from Operations | $ 50,071 | $ 21,099 | $ 122,450 | $ 58 | $ 18,894 | $ 212,572 | $ 463 | $ 618 | $ |

**At September 30, 2005**
**(Thousands)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| ent Assets | $ 1,401,128 | $ 782,546 | $ 1,213,525 | $ 90,468 | $ 162,052 | $ 3,649,719 | $ 73,354 | $ 2,209 | $ 3,725, |

**NATIONAL FUEL GAS COMPANY**

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

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

**Year Ended September 30, 2004**

| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber (Thousands) | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | T Cons |
|---|---|---|---|---|---|---|---|---|---|
| rom External s | $ 1,137,288 | $ 122,970 | $ 293,698 | $ 284,349 | $ 55,968 | $ 1,894,273 | $ 13,695 | $ | $ 1, |
| ent Revenues | $ 15,353 | $ 86,737 | $ | $ | $ 2 | $ 102,092 | $ | $ (102,092) | $ |
| come | $ 552 | $ 217 | $ 1,831 | $ 521 | $ 312 | $ 3,433 | $ 15 | $ (1,677) | $ |
| xpense | $ 21,945 | $ 10,933 | $ 50,642 | $ 33 | $ 2,218 | $ 85,771 | $ 919 | $ 3,062 | $ |
| ion, Depletion rtization | $ 39,101 | $ 37,345 | $ 89,943 | $ 102 | $ 6,277 | $ 172,768 | $ 1,071 | $ 450 | $ |
| ax Expense | $ 31,393 | $ 30,968 | $ 28,899 | $ 3,964 | $ 3,320 | $ 98,544 | $ 829 | $ (4,783) | $ |
| om idated es | $ | $ | $ | $ | $ | $ | $ 805 | $ | $ |
| t Item: ale of Timber . | $ | $ | $ | $ | $ 1,252 | $ 1,252 | $ | $ | $ |
| t Item: ale of Oil and ucing . | $ | $ | $ 4,645 | $ | $ | $ 4,645 | $ | $ | $ |
| Profit (Loss): Loss) from g Operations | $ 46,718 | $ 47,726 | $ 54,344 | $ 5,535 | $ 5,637 | $ 159,960 | $ 1,530 | $ (7,225) | $ |
| ures for to ed Assets from g Operations | $ 55,449 | $ 23,196 | $ 77,654 | $ 10 | $ 2,823 | $ 159,132 | $ 200 | $ 5,511 | $ |

**At September 30, 2004**
**(Thousands)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| t Assets | $ 1,355,964 | $ 783,145 | $ 1,078,217 | $ 68,599 | $ 140,992 | $ 3,426,917 | $ 77,013 | $ 213,673(1) | $ 3,71 |

(1) Amount includes $268,119 of assets of the former International segment, the majority of which has been discontinued with the sale of U.E. (See Note I Discontinued Operations).

| **Geographic Information** | **For the Year Ended September 30** | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| | | **(Thousands)** | |
| **Revenues from External Customers (1):** | | | |
| United States | $ 2,242,155 | $ 1,860,684 | $ 1,867,335 |
| Canada | 69,504 | 62,865 | 40,633 |
| | $ 2,311,659 | $ 1,923,549 | $ 1,907,968 |

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

| | At September 30 2006 | 2005 | 2004 |
|---|---|---|---|
| | | (Thousands) | |
| **Long-Lived Assets:** | | | |
| United States | $ 3,117,644 | $ 2,978,680 | $ 2,941,779 |
| Canada | 97,234 | 171,196 | 143,042 |
| Assets of Discontinued Operations | | | 228,179 |
| | $ 3,214,878 | $ 3,149,876 | $ 3,313,000 |

(1) Revenue is based upon the country in which the sale originates.

**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.

In September 2005, the Company recorded an impairment of $4.2 million of its equity investment in ESNE due to a decline in the fair market value of ESNE. This impairment was recorded in accordance with APB 18.

A summary of the Company s investments in unconsolidated subsidiaries at September 30, 2006 and 2005 is as follows:

| | At September 30 2006 | 2005 |
|---|---|---|
| | (Thousands) | |
| ESNE | $ 4,486 | $ 5,298 |
| Seneca Energy | 5,366 | 5,839 |
| Model City | 1,738 | 1,521 |
| | $ 11,590 | $ 12,658 |

Table of Contents

**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, 2006 | | | At September 30, 2005 |
|---|---|---|---|---|
| | Gross Carrying Amount | Accumulated Amortization | Net Carrying Amount | Net Carrying Amount |
| Intangible Assets Subject to Amortization: | | | | |
| Long-Term Transportation Contracts | $ 8,580 | $ (3,920) | $ 4,660 | $ 5,729 |
| Long-Term Gas Purchase Contracts | 31,864 | (5,026) | 26,838 | 28,431 |
| Intangible Assets Not Subject to Amortization: | | | | |
| Retirement Plan Intangible Asset (see Note G) | | | | 8,142 |
| | $ 40,444 | $ (8,946) | $ 31,498 | $ 42,302 |
| Aggregate Amortization Expense | | | | |
| For the Year Ended September 30, 2006 | $ 2,663 | | | |
| For the Year Ended September 30, 2005 | $ 2,663 | | | |
| For the Year Ended September 30, 2004 | $ 2,567 | | | |

The gross carrying amount of intangible assets subject to amortization at September 30, 2006 remained unchanged from September 30, 2005. 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 $1.1 million annually for 2007 and 2008. Amortization expense is estimated to be $0.5 million in 2009 and $0.4 million in 2010 and 2011. Amortization expense for the long-term gas purchase contracts is estimated to be $1.6 million annually for 2007, 2008, 2009, 2010 and 2011.

**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.

Table of Contents

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

| Quarter Ended | Operating Revenues | Operating Income | Income from Continuing Operations | Income (Loss) from Discontinued Operations | Net Income Available for Common Stock | Earnings from Continuing Operations per Common Share Basic | Earnings from Continuing Operations per Common Share Diluted | Earnings per Common Share Basic | Earnings per Common Share Diluted |
|---|---|---|---|---|---|---|---|---|---|
| | (Thousands, except per common share amounts) | | | | | | | | |
| **2006** | | | | | | | | | |
| 9/30/2006 | $ 294,469 | $ 18,444 | $ 1,968 | $ | $ 1,968(1) | $ 0.02 | $ 0.02 | $ 0.02 | $ 0.02 |
| 6/30/2006 | $ 415,452 | $ 8,541 | $ 111 | $ | $ 111(2) | $ | $ | $ | $ |
| 3/31/2006 | $ 890,981 | $ 138,967 | $ 78,594 | $ | $ 78,594(3) | $ 0.93 | $ 0.91 | $ 0.93 | $ 0.91 |
| 12/31/2005 | $ 710,757 | $ 110,123 | $ 57,418 | $ | $ 57,418(4) | $ 0.68 | $ 0.67 | $ 0.68 | $ 0.67 |
| **2005** | | | | | | | | | |
| 9/30/2005 | $ 287,064 | $ 34,926 | $ 18,311(5) | $ 30,900(6) | $ 49,211(5)(6) | $ 0.22 | $ 0.21 | $ 0.58 | $ 0.57 |
| 6/30/2005 | $ 400,359 | $ 63,028 | $ 26,393 | $ (7,237)(7) | $ 19,156(7) | $ 0.32 | $ 0.31 | $ 0.23 | $ 0.23 |
| 3/31/2005 | $ 735,842 | $ 120,667 | $ 63,981(8) | $ 6,702 | $ 70,683(8) | $ 0.77 | $ 0.75 | $ 0.85 | $ 0.83 |
| 12/31/2004 | $ 500,284 | $ 91,741 | $ 44,830 | $ 5,608 | $ 50,438 | $ 0.54 | $ 0.53 | $ 0.61 | $ 0.60 |

(1) Includes expense of $29.1 million related to the impairment of oil and gas producing properties.

(2) Includes expense of $39.5 million related to the impairment of oil and gas producing properties and income of $6.1 million related to income tax adjustments.

(3) Includes income of $5.1 million related to income tax adjustments.

(4) Includes income of $2.6 million related to a regulatory adjustment.

(5) Includes a $3.9 million gain associated with insurance proceeds received in prior years for which a contingency was resolved during the quarter, $3.3 million of expense related to certain derivative financial instruments that no longer qualified as effective hedges, $2.7 million of expense related to the impairment of an investment in a partnership, and $1.8 million of expense related to the impairment of a gas-powered turbine.

(6) Includes a $25.8 million gain related to the sale of U.E. and income of $6.0 million due to the reversal of deferred income taxes related to U.E.

(7) Includes $6.0 million of previously unrecorded deferred income tax expense related to U.E.

(8) Includes a $2.6 million gain on a FERC approved sale of base gas.

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

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

At September 30, 2006, there were 17,767 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, 2006 and 2005, are shown below:

| Quarter Ended | Price Range High | Price Range Low | Dividends Declared |
|---|---|---|---|
| **2006** | | | |
| 9/30/2006 | $ 39.16 | $ 34.95 | $ .30 |
| 6/30/2006 | $ 36.75 | $ 31.33 | $ .30 |
| 3/31/2006 | $ 35.43 | $ 30.60 | $ .29 |
| 12/31/2005 | $ 35.27 | $ 29.25 | $ .29 |
| **2005** | | | |
| 9/30/2005 | $ 36.00 | $ 27.74 | $ .29 |
| 6/30/2005 | $ 29.49 | $ 26.20 | $ .29 |
| 3/31/2005 | $ 29.75 | $ 26.66 | $ .28 |
| 12/31/2004 | $ 29.18 | $ 27.01 | $ .28 |

**Note O Supplementary Information for Oil and Gas Producing Activities**

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 2006 (Thousands) | At September 30 2005 (Thousands) |
|---|---|---|
| Proved Properties(1) | $ 1,884,049 | $ 1,650,788 |
| Unproved Properties | 41,930 | 39,084 |
| | 1,925,979 | 1,689,872 |
| Less Accumulated Depreciation, Depletion and Amortization | 929,921 | 721,397 |
| | $ 996,058 | $ 968,475 |

(1) Includes asset retirement costs of $42.2 million and $30.8 million at September 30, 2006 and 2005, respectively.

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

Costs related to unproved properties are excluded from amortization as they represent unevaluated properties that require additional drilling to determine the existence of oil and gas reserves. Following is a summary of such costs excluded from amortization at September 30, 2006:

| | Total as of September 30, 2006 | Year Costs Incurred 2006 | 2005 (Thousands) | 2004 | Prior |
|---|---|---|---|---|---|
| Acquisition Costs | $ 41,930 | $ 27,497 | $ 6,078 | $ 981 | $ 7,374 |

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

| | Year Ended September 30 2006 | 2005 (Thousands) | 2004 |
|---|---|---|---|
| **United States** | | | |
| Property Acquisition Costs: | | | |
| Proved | $ 5,339 | $ 287 | $ (8) |
| Unproved | 8,844 | 1,215 | 3,529 |
| Exploration Costs | 64,087 | 32,456 | 10,503 |
| Development Costs | 87,738 | 49,016 | 31,881 |
| Asset Retirement Costs | 10,965 | 8,051 | 2,292 |
| | 176,973 | 91,025 | 48,197 |
| **Canada** | | | |
| Property Acquisition Costs: | | | |
| Proved | (427) | (1,551) | 29 |
| Unproved | 6,492 | 4,668 | 3,167 |
| Exploration Costs | 20,778 | 22,943 | 22,624 |
| Development Costs | 14,385 | 12,198 | 5,500 |
| Asset Retirement Costs | 279 | 292 | 1,218 |
| | 41,507 | 38,550 | 32,538 |
| **Total** | | | |
| Property Acquisition Costs: | | | |
| Proved | 4,912 | (1,264) | 21 |

| | | | |
|---|---|---|---|
| Unproved | 15,336 | 5,883 | 6,696 |
| Exploration Costs | 84,865 | 55,399 | 33,127 |
| Development Costs | 102,123 | 61,214 | 37,381 |
| Asset Retirement Costs | 11,244 | 8,343 | 3,510 |
| | $ 218,480 | $ 129,575 | $ 80,735 |

For the years ended September 30, 2006, 2005 and 2004, the Company spent $55.6 million, $19.2 million and $12.1 million, respectively, developing proved undeveloped reserves.

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (Thousands, except per Mcfe amounts) | | |
| **United States** | | | |
| Operating Revenues: | | | |
| Natural Gas (includes revenues from sales to affiliates of $106, $77 and $72, respectively) | $ 152,451 | $ 151,004 | $ 151,570 |
| Oil, Condensate and Other Liquids | 195,050 | 160,145 | 139,301 |
| Total Operating Revenues(1) | 347,501 | 311,149 | 290,871 |
| Production/Lifting Costs | 41,354 | 38,442 | 39,677 |
| Accretion Expense | 2,412 | 2,220 | 1,756 |
| Depreciation, Depletion and Amortization ($1.74, $1.58 and $1.41 per Mcfe of production) | 66,488 | 67,097 | 73,396 |
| Income Tax Expense | 88,104 | 74,110 | 65,337 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | 149,143 | 129,280 | 110,705 |
| **Canada** | | | |
| Operating Revenues: | | | |
| Natural Gas | 54,819 | 49,275 | 30,359 |
| Oil, Condensate and Other Liquids | 13,985 | 12,875 | 10,018 |
| Total Operating Revenues(1) | 68,804 | 62,150 | 40,377 |
| Production/Lifting Costs | 14,628 | 12,683 | 8,176 |
| Accretion Expense | 258 | 228 | 177 |
| Depreciation, Depletion and Amortization ($2.95, $2.36 and $1.83 per Mcfe of production) | 27,439 | 23,108 | 14,922 |
| Impairment of Oil and Gas Producing Properties(2) | 104,739 | | |
| Income Tax Expense (Benefit) | (31,987) | 8,577 | 5,235 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | (46,273) | 17,554 | 11,867 |

**NATIONAL FUEL GAS COMPANY**

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | (Thousands, except per Mcfe amounts) | | |
| **Total** | | | |
| Operating Revenues: | | | |
| Natural Gas (includes revenues from sales to affiliates of $106, $77 and $72, respectively) | 207,270 | 200,279 | 181,929 |
| Oil, Condensate and Other Liquids | 209,035 | 173,020 | 149,319 |
| Total Operating Revenues(1) | 416,305 | 373,299 | 331,248 |
| Production/Lifting Costs | 55,982 | 51,125 | 47,853 |
| Accretion Expense | 2,670 | 2,448 | 1,933 |
| Depreciation, Depletion and Amortization ($1.98, $1.72 and $1.47 per Mcfe of production) | 93,927 | 90,205 | 88,318 |
| Impairment of Oil and Gas Producing Properties(2) | 104,739 | | |
| Income Tax Expense | 56,117 | 82,687 | 70,572 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | $ 102,870 | $ 146,834 | $ 122,572 |

(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.

***Reserve Quantity Information (unaudited)***

The Company s proved oil and gas reserves are located in the United States and Canada. 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 | Total Company |

| | | | | | | |
|---|---|---|---|---|---|---|
| Proved Developed and Undeveloped Reserves: | | | | | | |
| September 30, 2003 | 47,683 | 70,062 | 81,219 | 198,964 | 52,153 | 251,117 |
| Extensions and Discoveries | 2,632 | | 3,784 | 6,416 | 15,925 | 22,341 |
| Revisions of Previous Estimates | (4,984) | 1,831 | (1,111) | (4,264) | (11,004) | (15,268) |
| Production | (17,596) | (4,057) | (5,132) | (26,785) | (6,228) | (33,013) |
| Sales of Minerals in Place | (1) | (392) | | (393) | | (393) |

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

| | Gas MMcf | | | | | |
|---|---|---|---|---|---|---|
| | U. S. | | | | | |
| | Gulf Coast Region | West Coast Region | Appalachian Region | Total U.S. | Canada | Total Company |
| September 30, 2004 | 27,734 | 67,444 | 78,760 | 173,938 | 50,846 | 224,784 |
| Extensions and Discoveries | 17,165 | | 5,461 | 22,626 | 4,849 | 27,475 |
| Revisions of Previous Estimates | 6,039 | 7,067 | 3,733 | 16,839 | (1,600) | 15,239 |
| Production | (12,468) | (4,052) | (4,650) | (21,170) | (8,009) | (29,179) |
| Sales of Minerals in Place | | | (179) | (179) | | (179) |
| 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 |
| Proved Developed Reserves: | | | | | | |
| September 30, 2003 | 45,402 | 54,180 | 81,218 | 180,800 | 42,745 | 223,545 |
| September 30, 2004 | 25,827 | 53,035 | 78,760 | 157,622 | 46,223 | 203,845 |
| 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 |

| | Oil Mbbl | | | | | |
|---|---|---|---|---|---|---|
| | U.S. | | | | | |
| | Gulf Coast Region | West Coast Region | Appalachian Region | Total U.S. | Canada | Total Company |
| Proved Developed and Undeveloped Reserves: | | | | | | |
| September 30, 2003 | 3,383 | 63,852 | 138 | 67,373 | 2,391 | 69,764 |
| Extensions and Discoveries | 19 | | 18 | 37 | 181 | 218 |
| Revisions of Previous Estimates | 213 | (17) | 11 | 207 | (144) | 63 |
| Production | (1,534) | (2,650) | (20) | (4,204) | (324) | (4,528) |
| Sales of Minerals in Place | (1) | (303) | | (304) | | (304) |
| September 30, 2004 | 2,080 | 60,882 | 147 | 63,109 | 2,104 | 65,213 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Extensions and Discoveries | 99 | | 63 | 162 | 204 | 366 |
| Revisions of Previous Estimates | 105 | (1,253) | 3 | (1,145) | (186) | (1,331) |
| Production | (989) | (2,544) | (36) | (3,569) | (300) | (3,869) |
| Sales of Minerals in Place | | | | | (122) | (122) |

Table of Contents

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 | Total Company |
| 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 |
| Proved Developed Reserves: | | | | | | |
| September 30, 2003 | 2,533 | 40,079 | 139 | 42,751 | 2,391 | 45,142 |
| September 30, 2004 | 2,061 | 38,631 | 148 | 40,840 | 2,104 | 42,944 |
| 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 |

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

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.

Table of Contents

**NATIONAL FUEL GAS COMPANY**

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

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2006 | 2005 | 2004 |
| | | (Thousands) | |
| **United States** | | | |
| Future Cash Inflows | $ 3,911,059 | $ 6,138,522 | $ 3,728,168 |
| Less: | | | |
| Future Production Costs | 758,258 | 777,417 | 676,361 |
| Future Development Costs | 205,497 | 188,795 | 124,298 |
| Future Income Tax Expense at Applicable Statutory Rate | 1,019,307 | 1,868,548 | 995,327 |
| Future Net Cash Flows | 1,927,997 | 3,303,762 | 1,932,182 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | 1,066,338 | 1,812,230 | 996,813 |
| Standardized Measure of Discounted Future Net Cash Flows | 861,659 | 1,491,532 | 935,369 |

**Table of Contents**

**NATIONAL FUEL GAS COMPANY**

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | **2006** | **2005** | **2004** |
| | | (Thousands) | |
| **Canada** | | | |
| Future Cash Inflows | 197,227 | 601,210 | 343,026 |
| Less: | | | |
| Future Production Costs | 92,234 | 136,338 | 111,519 |
| Future Development Costs | 11,520 | 12,197 | 13,222 |
| Future Income Tax Expense at Applicable Statutory Rate | (151) | 137,524 | 60,610 |
| Future Net Cash Flows | 93,624 | 315,151 | 157,675 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | 19,375 | 108,508 | 46,945 |
| Standardized Measure of Discounted Future Net Cash Flows | 74,249 | 206,643 | 110,730 |
| **Total** | | | |
| Future Cash Inflows | 4,108,286 | 6,739,732 | 4,071,194 |
| Less: | | | |
| Future Production Costs | 850,492 | 913,755 | 787,880 |
| Future Development Costs | 217,017 | 200,992 | 137,520 |
| Future Income Tax Expense at Applicable Statutory Rate | 1,019,156 | 2,006,072 | 1,055,937 |
| Future Net Cash Flows | 2,021,621 | 3,618,913 | 2,089,857 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | 1,085,713 | 1,920,738 | 1,043,758 |
| Standardized Measure of Discounted Future Net Cash Flows | $ 935,908 | $ 1,698,175 | $ 1,046,099 |

Table of Contents

**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 | | |
|---|---|---|---|
| | 2006 | 2005 (Thousands) | 2004 |
| **United States** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | $ 1,491,532 | $ 935,369 | $ 733,248 |
| Sales, Net of Production Costs | (306,147) | (272,707) | (251,194) |
| Net Changes in Prices, Net of Production Costs | (941,545) | 1,093,353 | 592,326 |
| Purchases of Minerals in Place | 7,607 | | |
| Sales of Minerals in Place | | (762) | (5,554) |
| Extensions and Discoveries | 66,975 | 100,102 | 16,638 |
| Changes in Estimated Future Development Costs | (83,750) | (89,805) | (40,042) |
| Previously Estimated Development Costs Incurred | 67,048 | 25,038 | 32,653 |
| Net Change in Income Taxes at Applicable Statutory Rate | 404,176 | (362,956) | (166,055) |
| Revisions of Previous Quantity Estimates | 4,850 | 25,055 | (5,107) |
| Accretion of Discount and Other | 150,913 | 38,845 | 28,456 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | 861,659 | 1,491,532 | 935,369 |
| **Canada** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | 206,643 | 110,730 | 85,157 |
| Sales, Net of Production Costs | (54,176) | (49,467) | (32,201) |
| Net Changes in Prices, Net of Production Costs | (180,216) | 174,985 | 29,230 |
| Purchases of Minerals in Place | | | |
| Sales of Minerals in Place | (238) | (3,751) | |
| Extensions and Discoveries | 10,369 | 31,028 | 36,986 |
| Changes in Estimated Future Development Costs | (3,282) | (11,007) | (8,491) |
| Previously Estimated Development Costs Incurred | 4,450 | 12,032 | 5,055 |
| Net Change in Income Taxes at Applicable Statutory Rate | 82,966 | (51,541) | (2,640) |
| Revisions of Previous Quantity Estimates | (15,478) | (5,990) | (19,369) |
| Accretion of Discount and Other | 23,211 | (376) | 17,003 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | 74,249 | 206,643 | 110,730 |

**NATIONAL FUEL GAS COMPANY**

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

| | Year Ended September 30 2006 | 2005 (Thousands) | 2004 |
|---|---|---|---|
| **Total** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | 1,698,175 | 1,046,099 | 818,405 |
| Sales, Net of Production Costs | (360,323) | (322,174) | (283,395) |
| Net Changes in Prices, Net of Production Costs | (1,121,761) | 1,268,338 | 621,556 |
| Purchases of Minerals in Place | 7,607 | | |
| Sales of Minerals in Place | (238) | (4,513) | (5,554) |
| Extensions and Discoveries | 77,344 | 131,130 | 53,624 |
| Changes in Estimated Future Development Costs | (87,032) | (100,812) | (48,533) |
| Previously Estimated Development Costs Incurred | 71,498 | 37,070 | 37,708 |
| Net Change in Income Taxes at Applicable Statutory Rate | 487,142 | (414,497) | (168,695) |
| Revisions of Previous Quantity Estimates | (10,628) | 19,065 | (24,476) |
| Accretion of Discount and Other | 174,124 | 38,469 | 45,459 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | $ 935,908 | $ 1,698,175 | $ 1,046,099 |

**Schedule II Valuation and Qualifying Accounts**

| Description | Balance at Beginning of Period | Additions Charged to Costs and Expenses | Additions Charged to Other Accounts (Thousands) | Deductions(3) | Balance at End of Period |
|---|---|---|---|---|---|
| **Year Ended September 30, 2006** | | | | | |
| Allowance for Uncollectible Accounts | $ 26,940 | $ 29,088 | $ 907(1) | $ 25,508 | $ 31,427 |
| Deferred Tax Valuation Allowance | $ 2,877 | $ (2,877) | $ | $ | $ |
| **Year Ended September 30, 2005** | | | | | |
| Allowance for Uncollectible Accounts | $ 17,440 | $ 31,113 | $ 2,480(2) | $ 24,093 | $ 26,940 |
| Deferred Tax Valuation Allowance | $ 2,877 | $ | $ | $ | $ 2,877 |
| **Year Ended September 30, 2004** | | | | | |
| Allowance for Uncollectible Accounts | $ 17,943 | $ 20,328 | $ | $ 20,831 | $ 17,440 |
| Deferred Tax Valuation Allowance | $ 6,357 | $ (3,480) | $ | $ | $ 2,877 |

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

(2) Represents amounts reclassified from regulatory asset and regulatory liability accounts under various rate settlements ($4.5 million). Also includes amounts removed with the sale of U.E. (-$2.02 million).

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

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

None

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

**Evaluation of Disclosure Controls and Procedures**

The term disclosure controls and procedures is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within required time periods. 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, 2006.

**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, 2006. 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, 2006.

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 management s assessment of the effectiveness of the Company s internal control over financial reporting as of September 30, 2006. 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, 2006 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 and Executive Officers of the Registrant***

The information required by this item concerning the directors of the Company is omitted pursuant to Instruction G of Form 10-K since the Company s definitive Proxy Statement for its February 15, 2007 Annual

Table of Contents

Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2006. 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 2010, Directors Whose Terms Expire in 2009, Directors Whose Terms Expire in 2008, and Compliance with Section 16(a) of the Securities Exchange Act of 1934 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 February 15, 2007 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2006. 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 and the Corporate Performance Graph, 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 February 15, 2007 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2006. 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 February 15, 2007 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2006. 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 February 15, 2007 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2006. 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.

**Table of Contents**

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

None

**Item 13** ***Certain Relationships and Related Transactions***

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 February 15, 2007 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2006. The information regarding certain relationships and related transactions is set forth in the definitive Proxy Statement under the heading Compensation Committee Interlocks and Insider Participation 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 February 15, 2007 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2006. 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:<br>National Fuel Gas Company By-Laws as amended on December 9, 2004 (Exhibit 3(ii), Form 8-K dated December 9, 2004 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)
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)

**Table of Contents**

| Exhibit Number | Description of Exhibits |
|---|---|
| | 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) |
| | Amended and Restated Rights Agreement, dated as of April 30,1999, between the Company and HSBC Bank USA (Exhibit 10.2,Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880) |
| | Certificate of Adjustment, dated September 7, 2001, to the Amended and Restated Rights Agreement dated as of April 30,1999, between the Company and HSBC Bank USA (Exhibit 4, Form 8-K dated September 7, 2001 in File No. 1-3880) |
| | Officers Certificate establishing 6.50% Notes due 2022, dated September 18, 2002 (Exhibit 4, Form 8-K dated October 3, 2002 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) |
| 10 | Material Contracts: |
| | Contracts other than compensatory plans, contracts or arrangements: |
| | 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) |
| | 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) |
| | Compensatory plans, contracts or arrangements: |
| | Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, among the Company, National Fuel Gas Distribution Corporation and each of Philip C. Ackerman, Anna Marie Cellino, Paula M, Ciprich, Donna L. DeCarolis, James D. Ramsdell, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880) |
| | Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, among the Company, National Fuel Gas Supply Corporation and John R. Pustulka (Exhibit 10.2, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880) |
| | 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)

Table of Contents

| Exhibit Number | Description of Exhibits |
|---|---|
| | 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, amended through September 8, 2005 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 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 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) |
| | 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) |
| | Description of performance goals for Chief Executive Officer under the Company s Annual At Risk Compensation Incentive Program (Exhibit 10, Form 10-Q for the quarterly period ended December 31, 2004 in File No. 1-3880) |
| | Description of performance goals for Chief Executive Officer under the Company s Annual At Risk Compensation Incentive Program (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2005 in File No. 1-3880) |
| | Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated, effective March 9, 2005 (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2005 in File No. 1-3880) |
| | National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form10-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) |
| | 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, Form10-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)

| Exhibit Number | Description of Exhibits |
|---|---|
| | 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) |
| | 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) |
| | Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and Dennis J. Seeley (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1999 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 Dennis J. Seeley, dated March 29, 1999 (Exhibit 10.10, 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 Bruce H. Hale (Exhibit 10.11, 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 Bruce H. Hale, dated March 29, 1999 (Exhibit 10.12, 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) |
| | 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 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)

| Exhibit Number | Description of Exhibits |
|---|---|
| | 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) |
| | Retirement Benefit Agreement for David F. Smith, dated September 22, 2003,between the Company and David F. Smith (Exhibit 10.2, Form10-K for fiscal year ended September 30, 2003 in File No. 1-3880) |
| | Amendment No. 1 to the Retirement Benefit Agreement for David F. Smith, dated September 8, 2005, between the Company and David F. Smith (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| | Description of performance goals for certain executive officers (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2005 in File No. 1-3880) |
| | Retirement Agreement, dated August 1, 2005, between the Company and Bruce H. Hale (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| | Commission Agreement, dated August 1, 2005, between the Company and Bruce H. Hale (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| | Description of bonuses awarded to executive officer (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2006 in File No. 1-3880) |
| | Description of performance goals for certain executive officers (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2006 in File No. 1-3880) |
| | Noncompete and Restrictive Covenant Agreement, dated February 1, 2006, between the Company and Dennis J. Seeley (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 2006 in File No. 1-3880) |
| | Description of salaries of certain executive officers (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2006 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 10.2, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880) |
| | Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880) |
| 10.1 | Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit |
| | Retirement Agreement, dated July 1, 2006, between the Company and James A. Beck (Exhibit 10.4, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880) |
| | Contract for Consulting Services, dated July 1, 2006, between the Company and James A. Beck (Exhibit 10.5, Form 10-Q for the quarterly period ended June 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, 2002 through 2006 |
| 21 | Subsidiaries of the Registrant: See Item 1 of Part I of this Annual Report on Form 10-K |
| 23 | Consents of Experts: |

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|---|---|
| 23.1 | Consent of Ralph E. Davis Associates, Inc. regarding Seneca Resources Corporation |
| 23.2 | Consent of Ralph E. Davis Associates, Inc. regarding Seneca Energy Canada, Inc. |
| 23.3 | Consent of Independent Registered Public Accounting Firm |
| 31 | Rule 13a-15(e)/15d-15(e) Certifications |

Table of Contents

| Exhibit Number | Description of Exhibits |
|---|---|
| 31.1 | Written statements of Chief Executive Officer pursuant to Rule 13a-15(e)/15d-15(e) of the Exchange Act. |
| 31.2 | Written statements of Principal Financial Officer pursuant to Rule 13a-15(e)/15d-15(e) of the Exchange Act. |
| 32 | Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 99 | Additional Exhibits: |
| 99.1 | Report of Ralph E. Davis Associates, Inc. regarding Seneca Resources Corporation |
| 99.2 | Report of Ralph E. Davis Associates, Inc. regarding Seneca Energy Canada, Inc. |
| 99.3 | Company Maps |

The Company agrees to furnish to the SEC upon request the following instruments with respect to long-term debt that the Company has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A):

Secured Credit Agreement, dated as of June 5, 1997, among the Empire State Pipeline, as borrower, Empire State Pipeline, Inc., the Lenders party thereto, JPMorgan Chase Bank (f/k/a The Chase Manhattan Bank), as administrative agent, and Chase Securities, as arranger.

First Amendment to Secured Credit Agreement, dated as of May 28, 2002, among Empire State Pipeline, as borrower, Empire State Pipeline, Inc., St. Clair Pipeline Company, Inc., the Lenders party to the Secured Credit Agreement, and JPMorgan Chase Bank, as administrative agent.

Second Amendment to Secured Credit Agreement, dated as of February 6, 2003, among Empire State Pipeline, as borrower, Empire State Pipeline, Inc., St. Clair Pipeline Company, Inc., the Lenders party to the Secured Credit Agreement, as amended, and JPMorgan Chase Bank, as administrative agent.

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.

Table of Contents

## 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/ P. C. Ackerman
P. C. Ackerman
Chairman of the Board and Chief Executive Officer

Date: December 7, 2006

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<br>P. C. Ackerman | Chairman of the Board, Chief Executive Officer and Director | Date: December 7, 2006 |
| /s/ R. T. Brady<br>R. T. Brady | Director | Date: December 7, 2006 |
| /s/ R. D. Cash<br>R. D. Cash | Director | Date: December 7, 2006 |
| /s/ R. E. Kidder<br>R. E. Kidder | Director | Date: December 7, 2006 |
| /s/ C. G. Matthews<br>C. G. Matthews | Director | Date: December 7 2006 |
| /s/ G. L. Mazanec<br>G. L. Mazanec | Director | Date: December 7, 2006 |
| /s/ R. G. Reiten<br>R. G. Reiten | Director | Date: December 7, 2006 |
| /s/ J. F. Riordan<br>J. F. Riordan | Director | Date: December 7, 2006 |
| /s/ R. J. Tanski<br>R. J. Tanski | Treasurer and Principal Financial Officer | Date: December 7, 2006 |

| | | |
|---|---|---|
| /s/ K. M. Camiolo<br>K. M. Camiolo | Controller and Principal Accounting Officer | Date: December 7, 2006 |