# National Fuel Gas Company

## All the Right Elements

2007 Annual Report and Form 10-K

## ALL THE RIGHT ELEMENTS

National Fuel Gas Company is one of the few truly integrated companies within the natural gas and energy industries.

Our operating segments are assembled in an organization which actively participates across the full spectrum of the natural gas world, from exploration and production, to transportation and storage, to final customer delivery.

Much like the methane (natural gas) molecule depicted here, if any component of our company was absent, its stability could be seriously compromised. But our nearly $4 billion of assets are expertly invested across each of these segments, making us a stronger, steadier organization capable of generating consistent earnings results – and superior shareholder returns – over time.

Our business is far from elementary. It requires experienced, savvy leadership – and that's exactly what we've assembled at the board, executive, management and subsidiary levels. We have repeatedly proven the merits of our structure and the quality of our decisions. And our shareholders have enjoyed the benefits of our discipline time and time again. In the coming pages, you'll learn about what's next for this company with the 105-year track record. And most importantly, you'll see how you, as a shareholder, will benefit from our momentum.

## CORPORATE PROFILE

National Fuel Gas Company, incorporated in 1902, is a diversified energy company with its headquarters in Williamsville, New York. The Company's $3.9 billion in assets are distributed among five principal business segments: Exploration and Production, Pipeline and Storage, Utility, Energy Marketing, and Timber. National Fuel's history dates from the earliest days of the natural gas and oil industry in the United States and the Company has been responsible for many industry firsts. Today, the Company continues to be managed in the same innovative and entrepreneurial spirit and takes pride in its 105-year tradition of delivering service and value.

**Exploration and Production**

Seneca Resources Corporation explores for, develops and purchases natural gas and oil reserves in California, the Appalachian region, Wyoming, and the Gulf Coast region of Texas, Louisiana and Alabama. Currently, Seneca's exploration emphasis is centered on developing reserves and increasing production in the Appalachian region, economically producing our reserves in California, and exploring in the shallow Gulf of Mexico where we feel we have a competitive advantage.

**Pipeline and Storage**

National Fuel Gas Supply Corporation and Empire State Pipeline provide natural gas transportation and storage services to affiliated and nonaffiliated companies through an integrated system of 2,937 miles of pipeline and 32 underground natural gas storage fields (including four storage fields co-owned with nonaffiliated companies). This system is located within an area bounded by the Canadian border at the Niagara River, southwestern Pennsylvania and central New York, just north of Syracuse.

**Utility**

National Fuel Gas Distribution Corporation sells or transports natural gas to approximately 725,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by this system include Buffalo, Niagara Falls and Jamestown in New York, and Erie and Sharon in Pennsylvania.

**Energy Marketing**

National Fuel Resources, Inc. 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 to its customers.

**Timber**

Highland Forest Resources, Inc. and the Northeast Division of Seneca Resources Corporation carry out the Timber segment operations for the Company. Highland operates two sawmills in northwestern Pennsylvania. This segment markets timber and lumber from its New York and Pennsylvania land holdings.



This document 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 the Company's Form 10-K at Item 7, MD&A, under the heading "Safe Harbor for Forward-Looking Statements." Forward-looking statements are all statements other than statements of historical fact, including, without limitation, statements regarding future prospects, plans, performance and capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," and "may" and similar expressions.

# Financial Highlights

| Year Ended September 30, | 2007 | 2006 | 2005 | 2004 | 2003 |
|---|---|---|---|---|---|
| **Operating Revenues** (Thousands)[1] | **$ 2,039,566** | $ 2,239,675 | $ 1,860,774 | $ 1,867,875 | $ 1,821,899 |
| **Net Income Available for Common Stock** (Thousands) | **$ 337,455**[2] | $ 138,091[3] | $ 189,488[4] | $ 166,586 | $ 178,944[5] |
| **Return on Average Common Equity**[6] | **22.0%** | 10.3% | 15.3% | 13.9% | 16.7% |
| **Per Common Share** | | | | | |
| Basic Earnings | **$ 4.06** | $ 1.64 | $ 2.27 | $ 2.03 | $ 2.21[7] |
| Diluted Earnings | **$ 3.96** | $ 1.61 | $ 2.23 | $ 2.01 | $ 2.20[7] |
| Dividends Paid | **$ 1.21** | $ 1.17 | $ 1.13 | $ 1.09 | $ 1.05 |
| Dividend Rate at Year-End | **$ 1.24** | $ 1.20 | $ 1.16 | $ 1.12 | $ 1.08 |
| Book Value at Year-End | **$ 19.53** | $ 17.31 | $ 14.58 | $ 15.11 | $ 13.97 |
| **Common Shares Outstanding at Year-End** | **83,461,308** | 83,402,670 | 84,356,748 | 82,990,340 | 81,438,290 |
| **Weighted Average Common Shares Outstanding** | | | | | |
| Basic | **83,141,640** | 84,030,118 | 83,541,627 | 82,045,535 | 80,808,794 |
| Diluted | **85,301,361** | 86,028,466 | 85,029,131 | 82,900,438 | 81,357,896 |
| **Average Common Shares Traded Daily** | **593,424** | 445,802 | 322,887 | 223,600 | 221,021 |
| **Common Stock Price** | | | | | |
| High | **$ 47.87** | $ 39.16 | $ 36.00 | $ 28.43 | $ 27.51 |
| Low | **$ 35.02** | $ 29.25 | $ 26.20 | $ 21.71 | $ 17.95 |
| Close | **$ 46.81** | $ 36.35 | $ 34.20 | $ 28.33 | $ 22.85 |
| **Net Cash Provided by Operating Activities** (Thousands) | **$ 394,197** | $ 471,400 | $ 317,346 | $ 437,149 | $ 325,728 |
| **Total Assets** (Thousands) | **$ 3,888,412** | $ 3,763,748 | $ 3,749,753 | $ 3,738,103 | $ 3,740,944 |
| **Capital Expenditures** (Thousands) | **$ 276,728** | $ 294,159 | $ 219,530 | $ 172,341 | $ 152,251 |
| **Investment in Subsidiaries, Net of Cash Acquired** (Thousands) | **$ –** | $ – | $ – | $ – | $ 228,814 |
| **Volume Information** | | | | | |
| **Utility Throughput-MMcf** | | | | | |
| Gas Sales | **73,031** | 71,109 | 80,274 | 101,961 | 112,162 |
| Gas Transportation | **62,240** | 57,950 | 59,770 | 60,565 | 64,232 |
| **Pipeline & Storage Throughput-MMcf** | | | | | |
| Gas Transportation | **356,088** | 374,988 | 372,379 | 351,683 | 350,929 |
| **Production Volumes** | | | | | |
| Gas-MMcf | **26,266** | 25,771 | 29,179 | 33,013 | 33,805 |
| Oil-Mbbl | **3,450** | 3,608 | 3,869 | 4,528 | 6,737 |
| Total-MMcfe | **46,966** | 47,419 | 52,393 | 60,181 | 74,227 |
| **Proved Reserves** | | | | | |
| Gas-MMcf | **205,389** | 232,575 | 238,140 | 224,784 | 251,117 |
| Oil-Mbbl | **47,586** | 58,018 | 60,257 | 65,213 | 69,764 |
| Total-MMcfe | **490,905** | 580,683 | 599,682 | 616,062 | 669,700 |
| **Energy Marketing Volumes-MMcf** | | | | | |
| Gas | **50,775** | 45,270 | 40,683 | 41,651 | 45,135 |
| **Average Number of Utility Retail Customers** | **645,723** | 669,731 | 674,633 | 678,976 | 680,007 |
| **Average Number of Utility Transportation Customers** | **79,676** | 57,713 | 56,262 | 53,331 | 53,381 |
| **Number of Employees at September 30**[8] | **1,952** | 1,993 | 2,044 | 2,918 | 3,037 |

(1) Excludes discontinued operations.
(2) Includes gain on sale of Seneca Energy Canada, Inc. of $120.3 million.
(3) Includes impairment of oil and gas producing properties of ($68.6) million.
(4) Includes gain on sale of United Energy of $25.8 million.
(5) Includes gain on sale of timber properties of $102.2 million, loss on sale of oil and gas assets of ($39.6) million, and cumulative effect of changes in accounting of ($8.9) million.
(6) Calculated using average Total Comprehensive Shareholder Equity.
(7) Per common share amounts include an ($0.11) reduction to both basic and diluted earnings per share related to the cumulative effect of changes in accounting.
(8) Includes 0, 23, 26, 863 and 897 international employees at September 30, 2007, 2006, 2005, 2004 and 2003, respectively.

All references to years in this Annual Report are to the Company's fiscal year, which ends September 30.

# National Fuel's Integration

## Exploration and Production

**In 2007**

- Income from continuing operations of $74.9 million (also realized an after-tax gain of $120.3 million from the sale of Canadian exploration and production assets and achieved income of $15.5 million from the operation of those assets prior to sale).
- Total production of 47 Bcfe (56% natural gas and 44% oil), was within expectations, even after excluding sale of Canadian properties.
- Commenced drilling of 303 gross wells, an increase of 9% over 2006.
- Weighted average price received for domestic oil production increased $11.42 to $51.68 per bbl, an increase of 28.4%. Weighted average price received for domestic natural gas production increased $0.23 to $7.25 per mcf, an increase of 3.3%.

**2008 Outlook**

- Expand conventional Appalachian drilling program to drill 280 wells.
- Continue joint venture with EOG Resources to examine shale potential in our Appalachian acreage, with 18 wells anticipated to be drilled, 10 of which will be horizontal.
- Total capital budget of $154 million, compared to $146.7 million (for continuing operations) spent in 2007.
- Production goal of 38 to 44 Bcfe for streamlined operations in Appalachia, California and Gulf of Mexico.

## Pipeline and Storage

**In 2007**

- Net income of $56.4 million.
- Capital expenditures of $43.2 million.
- Signed contract with an anchor shipper and broke ground on the Empire Connector Project, a 78-mile, 24-inch pipeline designed to deliver 250 MDth of natural gas per day from the Empire Pipeline near Rochester, N.Y., to the Millennium Pipeline near Corning, N.Y.

**2008 Outlook**

- Anticipated completion of Empire Connector Project, with an in-service date of November 2008.
- Actively signing precedent agreements for development of West to East Pipeline Project to move Rockies Express and Appalachian local production to liquid delivery points at Leidy, Millennium Pipeline and other off-system points.
- Continually evaluate the gas storage market for acquisitions and economic storage expansion projects.

## Utility

**In 2007**

- Net income of $50.9 million.
- Filed rate case in New York, requesting a $52 million base rate increase, a revenue decoupling mechanism and a Conservation Incentive Program.
- Recognized nine-month impact of new rates in Pennsylvania, which contributed significantly to an increase in net income of $7.3 million in the Pennsylvania service territory compared to 2006.

**2008 Outlook**

- Conservation Incentive Program in New York was approved on September 19, 2007, with a final decision on base rates anticipated in December 2007.
- In New York, employ revenue decoupling mechanism (if approved) to achieve a margin based on allowed rate of return; and in Pennsylvania, continue to participate in generic case on revenue decoupling, facilitating the implementation of this program in that region.
- Continue to provide safe, reliable service while managing costs and maintaining high customer service standards.

## Energy Marketing

**In 2007**

- Net income of $7.7 million.
- Record throughput of 50.8 Bcf of natural gas, an increase of more than 12% from the previous year.
- Increased number of commercial and industrial accounts by 13.3%, and residential accounts by 2.6%.

**2008 Outlook**

- Continue to focus on core markets and market protection; and provide energy expertise to residential, commercial and industrial customers.

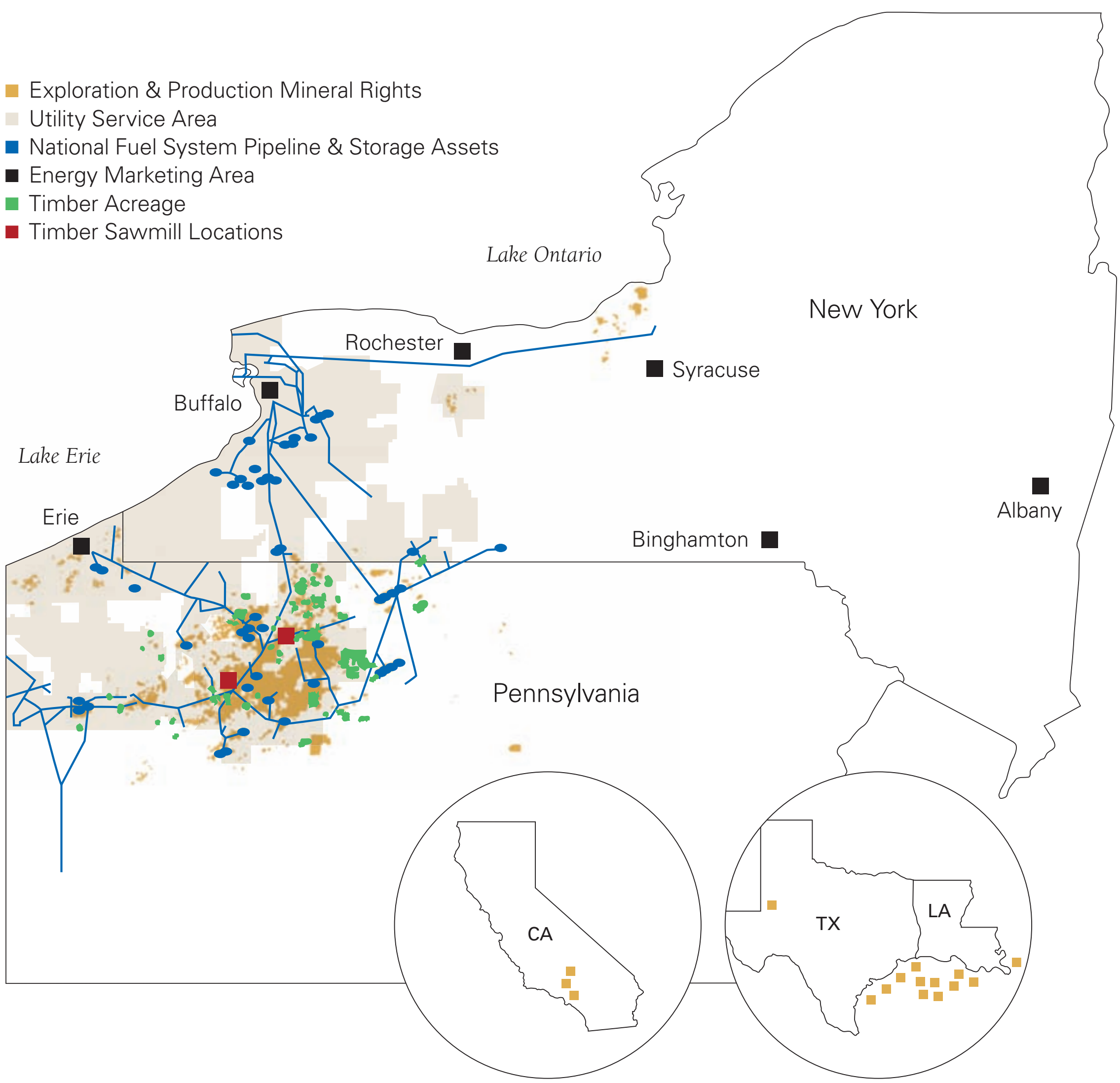
## Timber

**In 2007**

- Net income of $3.7 million.
- Completed installation of a new sorting facility at our mill in Marienville, Pa., which will help optimize the value of each log harvested.

**2008 Outlook**

- Continue to harvest quality hardwoods in a manner that is respectful to the environment, while facilitating natural regeneration of this resource.



Philip C. Ackerman (left)
Chairman and
Chief Executive Officer

David F. Smith
President and
Chief Operating Officer

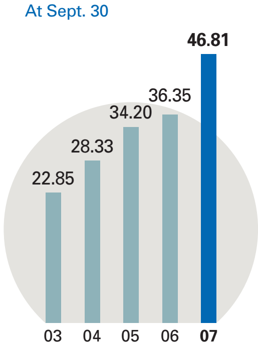
## To Our Shareholders

Record earnings, record stock price, record dividend, beating the S&P 500 total return for the last one-, three-, five- and 10-year periods—it doesn't get much better than this for a largely rate-regulated company that delivers real products and services with real assets. This year earnings of $3.96 per share, which include a significant gain from the sale of our Canadian assets, were made possible by contributions from each of our business segments. In addition to record financial performance, we accomplished a great deal in 2007 to prepare for continued successes in 2008 and beyond.

Just as the strength and value of the methane molecule result from the integration and balance of the elements that comprise it, the essence of your Company, including its strength and value, comes from the integration of its assets. Individually, these assets are inherently attractive, but joined together, they deliver superior performance, including a total return to shareholders of 32 percent in fiscal 2007.

We completed the sale of our Canadian Exploration and Production assets at an attractive price, realizing a gain of $1.41 per share, and we broke ground on the construction for the Empire Connector Pipeline, a 78-mile, 24-inch interstate pipeline designed to deliver 250 MDth of natural gas per day to growing markets in the Northeast and Mid-Atlantic. The Empire Connector Pipeline project remains on track to be in service in November 2008. In Appalachia, our 2007 drilling activity reached 233 wells. This activity, which is already robust, will be further accelerated in 2008 in the shallow formations and, through our joint venture with EOG Resources, in the deeper shale layer, as part of our aggressive plan to take full advantage of the potential of this asset.

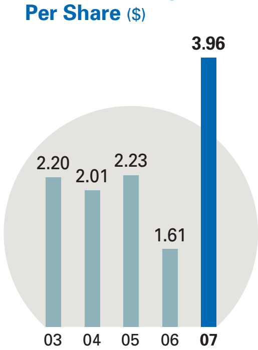
**NFG Share Price** ($)
At Sept. 30




In 2007, we continued our impressive dividend history, as your Board of Directors raised the dividend for the 37th consecutive year, making 2007 the 105th consecutive year of dividend payments to shareholders. In June, we increased the annual dividend rate by 3.3 percent to $1.24 per share. Increasing the dividend is something that our shareholders have come to expect and is something the Directors and Senior Management of your Company are committed to continuing for the foreseeable future.

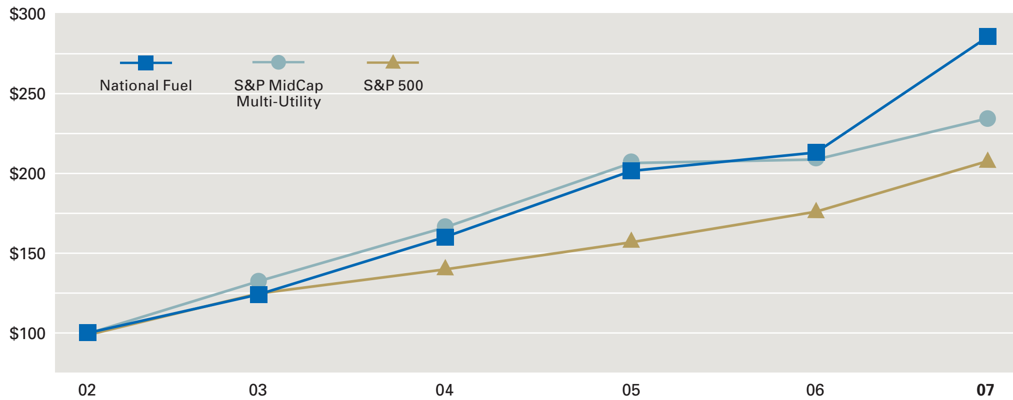
We have also taken many steps to improve our balance sheet and enhance our financial flexibility. At the end of our 2001 fiscal year, debt represented 62 percent of our total capitalization; by the end of this year, our debt was down to only 38 percent. During this same period of time, our book value per share grew from $12.63 to $19.53, an increase of more than 54 percent. At the same time, total dividends paid out to shareholders totaled $547.7 million and share repurchases amounted to $133.2 million. Our current financial strength offers us the flexibility to evaluate acquisitions and allocate capital for investments that represent a strategic fit.

**Diluted Earnings Per Share** ($)




Beyond these financial measures, in 2007, your Company also earned top-10 recognition for its performance from *Public Utilities Fortnightly*. This publication's analysis of the performance of U.S. utilities included a three-year average of free cash flow, return on equity, sustainable growth and profit margin. We are very proud to have achieved this high standing among nearly 100 other publicly traded companies this year, and to have been included among the top companies as rated by *Public Utilities Fortnightly* for several years.

**Total Shareholder Returns** [1]




[1]Assumes $100 invested on September 30, 2002, and reinvestment of dividends.

The underlying performance in each of our segments is the foundation for such recognition. Accomplishments like this, the commencement of our Empire Pipeline project and the significant increase of drilling activity on our Appalachian acreage since 2006, are among the things that made us stand out in terms of our success and our leadership in the energy industry.

Much of our success is due to being intimately familiar with our assets, most of which are within driving distance of our headquarters. Contrary to the old saying, familiarity has not bred contempt, but rather a deep appreciation for the integration of our pipeline, storage, utility, marketing, exploration, production and timber assets. After assembling most of our assets generations ago, we have worked diligently to maximize every opportunity they have offered. This has resulted in multiple uses of the same property, such as where timber and gas production or gas storage take place on the same parcel. The historic roots of many of these properties also mean they generally have a relatively low tax basis.

This integrated business as a whole, and the value proposition this structure creates for shareholders, has resulted in many years of tremendous performance. This track record was not achieved by accident, nor is it the result of shortsighted decision-making. Our strategic position, and the decisions that the management and Board of your Company make, are designed to enhance shareholder value both for today and for the long-term. This is not a process that began recently, but it is a philosophy that is deeply instilled throughout the organization. To the extent that we participate in all aspects of this industry and own real assets that have real value, we believe National Fuel combines all the right elements in a way that will lead to a consistent and successful performance through the varied cycles of the energy industry that are likely to continue.

This integration of assets is coupled with decades of experience. Together with Ron Tanski, your Chief Financial Officer, we have a combined 100 years of industry experience that includes the industry's boom and bust cycles. We have seen first-hand natural gas

## 2007 Performance Highlights

**EPS grew by 146%,** led by a $120 million after-tax gain on the sale of Canadian exploration operations.

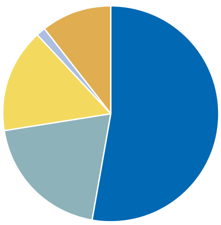
Generated a **total return to shareholders of 32%,** compared to 16% for the S&P 500.

Increased dividend for the **37th consecutive year,** to a rate of $1.24 per share annually.

**Began constructing the Empire Connector Project,** a 78-mile pipeline extending from near Rochester to Corning, N.Y., designed to deliver 250 MDth of natural gas per day.

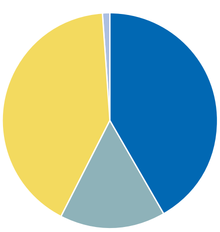
Increased Appalachia region drilling **by 53%** compared to 2006.

**Company Capital Expenditures, 2007**
(By Segment, in Millions)



| | |
|---|---|
| Exploration & Production | $ 146.7 |
| Utility | $ 54.2 |
| Pipeline & Storage | $ 43.2 |
| Timber | $ 3.7 |
| Discontinued Operations and All Other | $ 28.9 |
| | **$ 276.7** |

**Company Capital Expenditures, 2008 Estimated**
(By Segment, in Millions)



| | |
|---|---|
| Exploration & Production | $ 154.0 |
| Utility | $ 59.0 |
| Pipeline & Storage | $ 152.0 |
| Timber | $ 1.0 |
| | **$ 366.0** |

shortages transform into an oversupply bubble, and we now live with the current volatile pricing environment. By not over-committing to any one segment during these cycles, your Company has been able to produce consistent, reliable returns through the years.

Your Board and Management Team, the stewards of your investment, are resolved to make educated decisions based upon a long-term view, using the best information available. We will continually monitor and assess industry trends and developments; however, we will not move recklessly in a strategic direction without performing a diligent review of all of the options available and the long-term implications of each of those options. Nor will we seek to boost our stock price temporarily at the cost of sacrificing long-term value or competitive advantage. We will remain focused on the long-term consequences of those kinds of shifts in direction or philosophy and the resulting impact to your investment.

Our exploration and production activities in Pennsylvania and New York are a prime example. We have been producing oil and gas in this area for more than 100 years, with a level of drilling that has ebbed and flowed as fluctuating gas prices and changes in technology have affected the fundamental economics of drilling. In today's high-price environment, we are implementing an aggressive knowledge-based plan to fully develop the shallow sands. We plan to increase our Appalachian drilling at a pace consistent with controlling well quality, capital expenditure per producing well and time-to-first-production for each new well. In 2007, we increased the number of wells drilled by 53 percent, to a total of 233 in the Devonian and Silurian formations, and the estimate of average reserves per well from these newer wells increased 39 percent to 97 MMcfe, up from 70 MMcfe in 2006.

We anticipate drilling 280 wells in fiscal 2008 in the Appalachian shallow formations and increasing that activity to 350 wells in fiscal 2009. Our strategy and development plan are based on our proprietary data, our ongoing geologic work and the extensive knowledge and expertise of both our long-time and our newly added Appalachian geologists and engineers.

The geologic features, or stratigraphy, of our part of the Appalachian Basin are complex and variable. Highly successful wells with estimated ultimate recoveries ("EURs") exceeding 300 MMcfe can have adjacent offset wells that are subeconomic. Wells in one part of a county can have average EURs that are twice the average EURs of wells 30 miles away in the same county. It would be reckless to embark on a drilling program that failed to take into account the complex stratigraphy of the actual geologic formations to be drilled.

All available information, including information to come from wells not yet drilled, must be utilized in order to optimize the results of future wells. Drilling too many wells too rapidly would eliminate opportunities to make informed decisions in favor of forging blindly ahead, likely causing average well quality to decline, leading to

Seneca Resources was a leader in exploration and production activity in the Appalachian region in 2007. The 233 wells drilled here represent the most in any one year in the Company's history, and we plan to drill 280 wells in the upper Devonian sandstone formations in 2008.

delays in first production and significantly reducing the net present value of assets. In this segment of our business, returns on capital erode quickly as well costs increase, reserves per well decrease or the time between drilling and commencement of production lengthens. We can continue to increase Appalachian drilling activity and production and enhance overall value by making informed decisions.

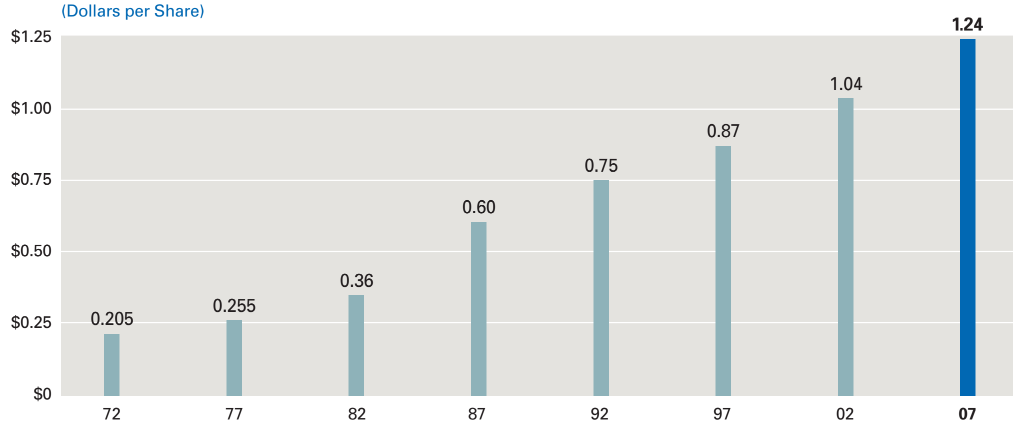
In September, construction began on the 78-mile-long Empire Connector Pipeline Project. Phase One involved approximately 19 miles of the 24-inch pipeline (shown here) to be installed in Yates and Schuyler counties. Phase Two will commence in spring 2008, with the remaining mileage to be completed by November.

Over the years, our experience has been that opportunities result from the control of assets. The prime current example of that is our Appalachia acreage and the Marcellus Shale formation. The presence of gas in this shale has been known for years, but it is only relatively recently that drilling in shale has become economic in other parts of the country thanks to rising gas prices and large strides in technology. Now attention has turned to the Marcellus Shale formation.

We are examining the Marcellus Shale with EOG Resources, an industry leader that has successfully explored and developed shale formations. Although this opportunity is in its initial stages, we remain excited about this play and are prepared to allocate the resources necessary to thoroughly evaluate and exploit it. To date, we have drilled three vertical wells and one horizontal well and plan to drill 18 wells in fiscal year 2008, 10 of which will be horizontal. By early 2008, we expect to have results for three vertical wells and three horizontal wells on our acreage. The potential of our Marcellus Shale position is tremendous, but at this point, it is far from a sure thing. While other shales have taken years to understand, with a first-class partner dedicated to this effort, we are both hopeful and excited about this asset.

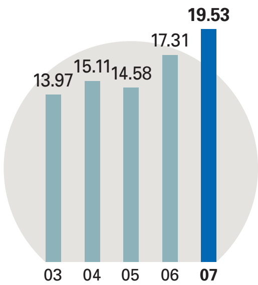
Our financial structure remains elegant in its simplicity. We have equity and we have debt, with nothing in between, save some minor operating leases. Over the years we have looked at a great many forms of financial reengineering and generally found them to be inapplicable, inappropriate, unnecessary or misleading. This year's look at Master Limited Partnerships ("MLPs") was no exception.

**Annual Dividend Rate at Year End**
(Dollars per Share)



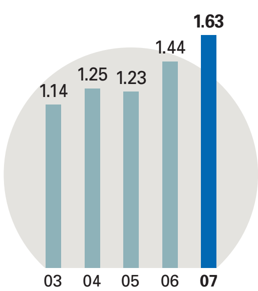
MLPs seem attractive on their face as tax-sheltered, clever ways to increase value. But after months of painstaking analysis, with the help of top-tier lawyers and investment bankers, we concluded that, in our situation, an MLP of either production or pipeline and storage assets would not increase earnings per share, nor result in an increase in the net present value of our assets. In particular, the low tax basis of our assets offset much of the benefit usually seen in an MLP. At the end of the day, for us, an MLP was all sizzle and no steak, and we will not sell our investors a product without substance.

**Book Value Per Common Share** ($)
At Sept. 30




We take this opportunity to thank our Board, without whom the Company's success would not be possible. Their understanding of this industry and their active involvement in our decision-making and strategic planning have been essential to the consistent performance shareholders have come to expect. Our existing Board of Directors has a wealth of experience in the natural gas industry and we are very fortunate to have what we believe is the best Board of Directors in the industry. Considering the above-average returns our stock has provided, our consistent dividend record, the record earnings attained during 2007 and the fact that our stock has traded at an all-time high as recently as today, we are reminded of the value this team of experts brings to your Company. Their business decisions continue to demonstrate the wealth of knowledge and experience they've gained through careers in all facets of the natural gas industry, and in business in general.

**Total Comprehensive Shareholders' Equity**
($ in Billions, at Sept. 30)




In February, we also welcomed two new members to the Board with the election of Dave Smith, our current President and Chief Operating Officer, and Steve Ewing, former Vice Chairman and Group President of the Gas Division at DTE Energy, making our 10-person board composed 80 percent of independent directors. Their experience and dedication to the long-term objectives of your Company will make them ideal accompaniments to this distinguished group. As you review similarly situated companies, you will see few, if any, Boards with industry expertise or qualifications exceeding those of your Company's Directors.

In 2007, several members of the Management Team at your Company were promoted in recognition of their years of dedicated and expert service and we welcomed a key addition to our Exploration and Production team. In November 2007, Donna DeCarolis was promoted to the newly created position of Vice President Business Development for National Fuel Gas Company. Donna will be responsible for pursuing acquisition opportunities and will also remain President of our landfill gas and power generation subsidiaries. At that same time, Joe Del Vecchio was promoted to Vice President of National Fuel Resources, Inc., and will be responsible for your Company's Energy Marketing segment. During 2007, Jeff Hart, Sarah Mugel and Michael Reville were promoted

The new Bayfront Convention Center, located on Lake Erie's Presque Isle Bay in Erie, Pennsylvania, opened in the summer of 2007. This $44 million facility is the largest development in the City of Erie's history and is expected to increase the Utility segment's throughput by approximately 13,400 Mcf per year.

Horizon Power expanded its landfill gas processing plant in 2007 by adding four new Caterpillar 3520 engines, each with a generation capacity of 1.6 megawatts (MW). The plant, which is owned in partnership with Innovative Energy Systems, recovers methane gas from landfills as an alternative energy source for power generation. These new engines increase Horizon's capacity from 11.2 MW to 17.6 MW – more than 50 percent. Pictured are: Scott Henningham, Chief Financial Officer of Innovative Energy Systems (left), and Matthew Frank, Asset Manager of Horizon Power.

to Assistant Vice Presidents of National Fuel Gas Distribution Corporation; Duane Wassum was promoted to President of Highland Forest Resources, Inc.; and in Supply Corporation, Jim Peterson was promoted to Secretary, Dave Bauer was promoted to Treasurer, and Ron Kraemer was promoted to Assistant Vice-President. Also, in March 2007, John McGinnis was hired as Senior Vice President of Seneca Resources to help grow our exploration and production business.

We also thank all of our employees who work diligently throughout every area of this Company, each of whom has a remarkable role in our success. Their hard work and dedication make our extraordinary results attainable, again and again. Our employees have also demonstrated their generosity and dedication to our service areas as, together with matching gifts provided by the National Fuel Gas Company Foundation, more than $2.6 million has been donated to more than 600 charities and organizations in the areas where we live, work and beyond, during the past three years. This further demonstrates that the people at National Fuel are not only first-rate with their minds and their hands, but as well with their hearts.

We have developed a proud history of success, leadership and expertise in the energy industry during the last 105 years. Our competitive advantage rests in our experience and the assets that have been assembled into your Company. Our experience has taught us to expect change, how to manage the cycles in our industry and that the development of reliable strategies has a foundation in careful consideration of reliable data. That experience, whether it is gained in the field or by sitting at the table in our boardroom, cannot be easily replaced. We take our role of managing all of the elements of your Company very seriously, are proud of the job we've done and remain dedicated to providing superior benefit to shareholders today, tomorrow, and far into the future.

Philip C. Ackerman

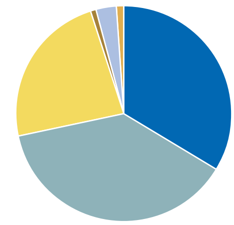
**Philip C. Ackerman**
Chairman of the Board and Chief Executive Officer

David F. Smith

**David F. Smith**
President and Chief Operating Officer

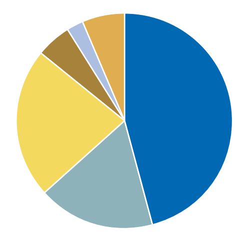
December 7, 2007

**Net Property, Plant and Equipment**
($ in Millions, At Sept. 30, 2007)



| | |
|---|---|
| Exploration & Production | $ 982.7 |
| Utility | $ 1,099.3 |
| Pipeline & Storage | $ 681.9 |
| Energy Marketing | $ 0.1 |
| Timber | $ 89.9 |
| All Other & Corporate | $ 24.5 |
| | **$ 2,878.4** |

**Net Cash Provided By Operating Activities**
($ in Millions, By Segment, in 2007)



| | |
|---|---|
| Exploration & Production | $ 181.1 |
| Utility | $ 68.6 |
| Pipeline & Storage | $ 89.7 |
| Energy Marketing | $ 20.1 |
| Timber | $ 10.0 |
| All Other & Corporate | $ 24.7 |
| | **$ 394.2** |

## Exploration and Production

Our Exploration and Production segment has captured the attention of the financial community. In Appalachia, or our East Division, Seneca's ownership of nearly 940,000 mineral acres is one of the largest positions in the Appalachian Basin. From a historical viewpoint, this acreage is relatively underdeveloped as the property's economics generally have been marginal except in today's higher natural gas price environment. It is far more profitable now to develop these assets than it had been. As a result, we have significantly accelerated our drilling and capital spending in this region.

Net income from continuing operations in this segment totaled $74.9 million (which excludes a $120 million after-tax gain on the sale of our Canadian operations) and represented a substantial increase compared to the $67.5 million of income from continuing operations achieved in fiscal 2006. In addition, in 2007, we commenced the drilling of 233 wells, targeting shallow tight-gas zones, that compared to 152 wells drilled in 2006 and 83 in 2005. Our fiscal 2008 target for shallow gas drilling is 280 wells.

Production in the East Division increased to 6.3 Bcfe from 5.5 Bcfe in fiscal 2006. We expect continued growth in fiscal 2008 with a production target of 7.3 Bcfe. We also added proved reserves of 33 Bcfe for a reserve replacement of more than 500 percent. In addition, a study by the engineering firm Netherland, Sewell & Associates, indicated 110 Bcfe of Probable and Possible reserves, for total 3P reserves of 220 Bcfe on Seneca's Appalachia properties.

We continue to work on our Marcellus Shale joint venture with EOG Resources, as four wells have been drilled to date, three of which are vertical and one of which is horizontal. We expect to ramp up our Marcellus Shale drilling in 2008 with 18 wells anticipated, 10 of which will be horizontal. Although we are in the very early stages of this program, we remain eager and optimistic and plan to devote the technical expertise and resources necessary to quantify the potential of this asset.

In the Gulf Coast Division, our efforts have been more narrowly focused. Midway through 2007, we cut back our Gulf capital spending and have since focused our program to areas where we have a competitive advantage, specialized knowledge or recent success. In March 2007, a well at High Island 24L – North was drilled as an offset to our previous HI 24L – South discovery. The two-well HI 24L Field is now online and producing at 70 MMcfe per day. Seneca has a 35 percent working interest in the project. Overall, Gulf of Mexico production is forecast to be up five to 10 percent in 2008 when compared to fiscal 2007. We will continue our more disciplined and focused program in 2008 with capital spending anticipated to decrease by 24 percent compared to fiscal 2007.

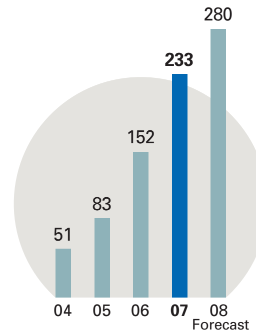
In the West Division, or California, we continue efforts to maintain the production level of 18.3 Bcfe that we achieved in 2007. In another step to increase the efficiency of these operations, we expanded the steam flood capacity and enhanced the waste gas scrubber operations. Our highly efficient and well-run operations in California make us a low-cost producer and this division continues to provide excellent cash flow.

In the fourth quarter, Seneca streamlined operations by completing the successful divestiture of our Canadian assets. Effective August 31, 2007, these assets were sold for $232 million, which represented an after-tax gain of more than $120 million. This sale represented 48.8 Bcfe of reserves, which contributed about 24 MMcfe per day of production. Although this divestiture will reduce our annual production by about 9 Bcfe annually, we expect to realize overall improved finding and development costs and an ability to focus our attention on other areas.

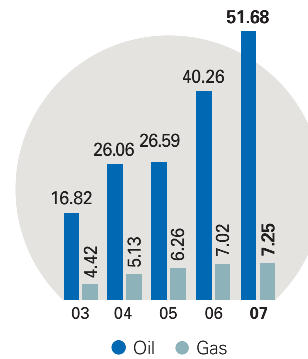
In 2008, we expect to spend more than $150 million of capital and expect production to be between 38 and 44 Bcfe, as compared to domestic production of 39 Bcfe in 2007. We expect production increases in the Appalachian and Gulf regions while California production should remain nearly flat. We have hedged 12.2 Bcf of 2008 natural gas production at an average price of $8.47 per Mcf on swaps, a floor price of $8.83 per Mcf on no-cost collars and 1.4 million bbl of heavy oil production with an average price of $58.78 per bbl on swaps.

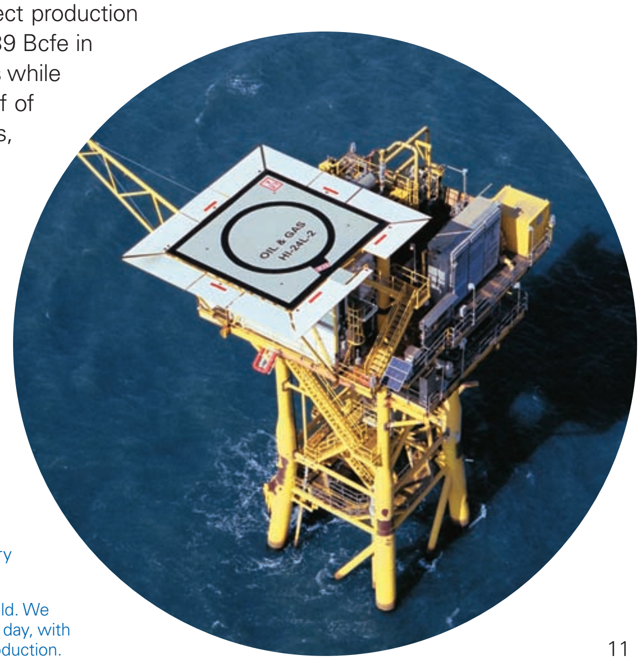
We are aggressively working to continue to reduce finding and development costs and improve reserve replacement. We have high-quality assets, a well-focused plan and an experienced and talented staff. We expect that this segment will be the near-term growth engine for the Company, and have mapped out an aggressive, but prudent strategic plan, to optimize value over the long-term.

**Wells Drilled In Appalachia**
Year Ending Sept. 30




**Oil and Gas Prices**
($, Weighted Average After Hedging)




◄ This well is one of more than 2,200 net producing wells which our Seneca Resources subsidiary owns and operates in the Appalachian region.

► In the Gulf of Mexico, the highlight of fiscal 2007 was the development of the High Island 24L Field. We began production in mid-October 2007 and are producing approximately 70 Mcfe of natural gas per day, with a 35 percent working interest. This two-well field is currently 16 percent of the Company's total production.

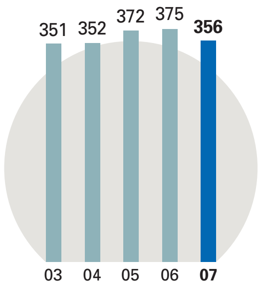
## Pipeline and Storage

There has been a great deal of activity in this segment and in this part of the energy industry in general, and we stand ready to take advantage of the growth opportunities that will emerge as a result. Because of our geographic location, natural gas can move through our system from Canada, Appalachia, the Rocky Mountains, the Midwest or the Gulf of Mexico to reach growing markets in the Northeast and Mid-Atlantic. We also benefit by being located in one region of North America where it is possible to store natural gas in close proximity to the Northeast markets.

A welder works on a pipeline replacement project in Allegany State Park's popular Thunder Rocks area. Known for its primitive forested valleys, un-glaciated landscape, fall leaves and wildlife, this park has been home to our pipeline for decades where it has co-existed with this natural treasure without incident or intrusion.

The strategic location of our pipeline and storage assets, relative to our other assets and to other interstate pipeline systems, is the underpinning to its value within the Company. Its earnings of $56.4 million in 2007 were $800,000 more than those achieved in 2006. A $4.8 million reversal of preliminary costs related to the Empire Connector, coupled with a $1.9 million gain associated with the discontinuance of hedge accounting on an interest rate collar, represented one-time benefits. This was offset by a $5.9 million decrease in operating results related to the FERC-approved rate settlement with Supply Corporation. This settlement, which became effective on December 1, 2006, and will be in place for five years, gives us the certainty and opportunity to restore earnings to their prior level and beyond.

**Total Throughput Volumes (Bcf)**
Year Ending Sept. 30




The Empire Connector is our next significant expansion and we reached key development milestones last year. A binding service agreement was signed with an anchor shipper that has subscribed for 60 percent of the pipeline's capacity. We broke ground on the pipeline in September and expect that approximately 19 miles of the 78-mile route pipeline will be complete by the end of December. In 2008, the remainder of the pipeline will be constructed and a 20,000 horsepower compressor station will be built in Oakfield, N.Y. We are aggressively marketing the remaining capacity, which we expect will be accessible by November 2008. This $177 million pipeline is designed to deliver 250 MDth daily to the Millennium Pipeline or other interconnects. For several years we have not had major growth in this segment because of a lack of available takeaway capacity to the East. With the Empire Connector and Millennium Pipeline, we will soon gain access to East Coast markets, breaking the logjam that stymied expansion in prior years.

In the spring of 2007, we solicited interest in another pipeline project that would transport gas from the Rockies Express Pipeline and local production sources to our Supply Corporation's pipeline and storage system. We received extraordinary market interest for this endeavor, totaling nearly 1 Bcf of daily transportation capacity for a pipeline that is likely to be designed at a capacity of 550-750 MDth per day. The project could include building up to 324 miles of new pipe to connect the terminus of the Rockies Express at Clarington, Ohio, to the southeast portion of our system. We differentiate ourselves from other similar proposals with the opportunity to use existing right-of-way for up to 75 percent of our proposed route, and through our ability to include storage services to shippers following expansion at certain existing storage fields. Currently, we are performing our due diligence work to determine if this project is economically viable.

80-foot sections of the Empire Connector Pipeline are removed from rail cars arriving from Louisiana, where our custom-ordered pipe was manufactured.

We continually seek ways to add incremental storage capacity via acquisition and expansion. The market values this asset in our system, as all of our storage customers will be contracted at maximum tariff rates by April 2008. In the past, in response to shifts in demand driven by seasonal and general market demand, we have discounted rates to maximize revenue and ensure a fully subscribed system. However, with continued disruption concerns from Gulf Coast sources, a growing need for local production and the desire of downstream customers to shed year-round long-haul capacity, storage has become a solution, regardless of commodity prices.

As the investing community focuses on the natural gas potential within Appalachia, we stand poised to move this local production to market. There are approximately 140 MDth of local production transported on our system each day. Moreover, nearly 100 producers were actively drilling wells in close proximity to our pipeline system during calendar 2006. We expect increased drilling in this area as new geologic formations become economic at current commodity prices. This presents a tremendous opportunity for this segment to transport this production to high-demand areas.

◄ Rows and rows of pipe are ready to be installed in Yates and Schuyler counties as part of the Empire Connector Pipeline's first phase. We have a long track record of operating our nearly 3,000-mile pipeline network in a safe, reliable fashion. This project was no different, as countless special considerations were made when working on or near agricultural and other environmentally sensitive lands along the route.

## Utility

In this segment, we continue to invest in our infrastructure to ensure all 725,000 of our customers receive the quality service upon which they have always relied. In fiscal year 2007 alone, $54 million of capital was invested to improve our system. In order to cover the costs of such investments, new rates became effective for the Pennsylvania jurisdiction; and in New York, a request was filed to raise base rates.

In 2007, new rates in our Pennsylvania jurisdiction and increased throughput due to colder weather helped to produce $50.9 million in net income. Although this represents an overall increase of $1.1 million from the previous year, earnings across our two jurisdictions were quite different. In Pennsylvania, net income increased by $7.3 million, while in New York net income was $6.2 million lower than last fiscal year. One-time regulatory events caused New York's earnings to be more than $4 million lower than the previous year, including a positive symmetrical sharing adjustment in 2006 that did not recur in 2007 and other negative regulatory true-ups.

In January, we filed a request with the New York State Public Service Commission ("PSC") to increase base rates to account for increased operation and maintenance expenses and necessary system upgrades, among other things. The filing included a proposal for a revenue decoupling mechanism ("RDM") to manage the declining revenue due to customer conservation measures. Initiatives like this have been successful in other jurisdictions as a tool to remove impediments that create disincentives for utilities to promote conservation and efficiency programs to customers. An RDM permits an adjustment to delivery service charges based upon throughput, allowing the Utility to recover its appropriate operating margin irrespective of customer usage.

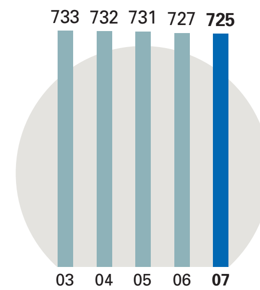
Included with the RDM filing was a comprehensive program to promote conservation and efficient use of natural gas in Distribution's New York service territory. The Conservation Incentive Program ("CIP") was approved by the Commission in September 2007 with a funding allowance of $10.8 million. The CIP includes rebates for the purchase of certain high efficiency appliances, targeted efficiency audits and special low-income weatherization assistance. The goal of the program is to help change customers' long-term energy-use behavior. If successful, these efforts can have a positive impact in the energy marketplace by helping to reduce demand for natural gas. We received early approval for this program, and with its November 1, 2007, start date, customers were able to benefit from this initiative beginning this heating season. A decision from the PSC on the other matters in the rate case, including the RDM, is expected in December 2007.

The New York division's Area Development Program, an innovation from our last filed rate case, continues to offer economic development incentives to area businesses that are either new to or are growing in western New York. The expected benefits resulting from more than $660,000 offered in grants since the program's inception include 5,471 new jobs and more than $296 million in private investment. In this way, the Area Development Program offers job security, incremental hiring and economic development opportunities that benefit our service territory and the Utility alike.

In Pennsylvania, new rates that were only in effect for the last nine months of fiscal 2007 contributed to record earnings. The resulting increase in after-tax earnings of $5.5 million, along with the incremental $2.5 million in earnings due to weather that was 5.6 percent colder than the previous year, made this a very profitable year. The anticipated gross revenue impact on an annual basis is expected to be $14.3 million, and fiscal year 2008 will be the first year to realize the benefit of higher rates over an entire year.

Along with our investment in the Utility's infrastructure, the commitment our workforce makes to provide service that is at the highest level remains a top priority for the Company. When our customers call, they speak with a trained customer service representative who is skilled at responding personally to their needs. Our field operations personnel work diligently to provide continuous delivery of clean-burning natural gas to the homes and businesses in our service area. Their dedication and commitment to first-rate service is proven time and time again, and we continue to take pride in the fact that our customers consistently report high satisfaction for the service they receive.

**Number of Utility Customers**
(Thousands)




**Utility Customer Service Metrics**
(Fiscal 2007)

Appointments Kept:
**99.1%**

Customer Satisfaction:
**89.3%**

Calls Answered Within 30 Seconds:
**85.3%**

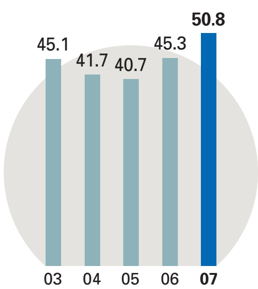
▶ In late October 2006, in collaboration with the Gas Technology Institute, National Fuel began testing Polyamide 12 piping (PA 12), the next generation of plastic pipe. Two sections of pipe, each made by a different manufacturer, were buried. Over the next two years, they will be monitored to evaluate the field environment's effects on them. This research not only gives us experience with this new pipe, but also determines its capabilities. Pictured to the right is Dan Tomich, a National Fuel Gas Distribution Corporation engineer.

▶ In a national event sponsored by NYSEARCH, a research and development organization within the Northeast Gas Association, National Fuel hosted the first-ever launch of a tetherless, self-propelled robotic inspection system for higher pressure pipeline networks. Here, a third-party contractor guides the robot, which represents the future of inspecting and maintaining utilities nationwide, into a line within the Brookville, Pa. district.

## Energy Marketing

Since the early 1990s, National Fuel Resources, Inc. ("NFR") has been a key participant in the non-utility supplier market in our integrated corporate structure. We believe it is important to have a reliable natural gas marketer committed to the long-term and that NFR's consistency, longevity and competitive prices have been the cornerstone of its success. This segment continues to be the market leader in the National Fuel Utility service area, and is a growing force in nearby utility service areas. With minimal capital investment, NFR posted another strong year, increasing earnings from $5.8 million in fiscal 2006 to $7.7 million in fiscal 2007.

**NFR Natural Gas Marketing Volumes**
(Bcf)

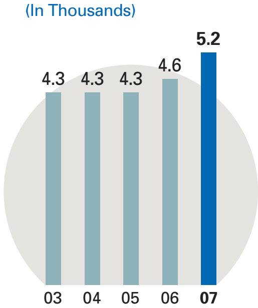



Capitalizing on a proven record and superior service, NFR expanded into contiguous utility markets in fiscal 2007. Incremental retail sales to National Grid, Rochester Gas & Electric and New York State Electric & Gas customers, together with wholesale sales, set NFR's throughput at a record level of 50.8 Bcf, an increase of 5.5 Bcf from fiscal 2006. Retail sales comprised 61 percent of this volume, a 3 percent increase over last year, while wholesale volumes made up the remaining 39 percent.

NFR's focus on customer satisfaction has earned it loyalty and endorsements. Last year it launched a new residential referral program that rewards customers for referrals to friends and neighbors. NFR remains the largest marketer on our Utility system, accounting for 40 percent of transportation volumes in 2007. In addition, because NFR is a significant customer of our Pipeline and Storage segment and a growing customer of our Empire State Pipeline, it creates value for your Company. Today's complex energy market requires well-honed operational, sales and risk management expertise. NFR understands these challenges and is well-positioned for the long-term.

## Timber

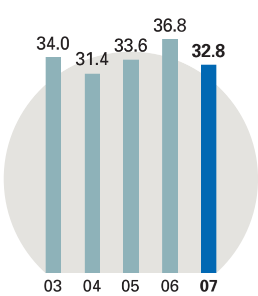
**NFR Number of Non-residential Customers**
(In Thousands)




Our Timber segment experienced another solid year with earnings of $3.7 million, which were in line with our expectations. The $2 million decrease from last year was due to lower sales volumes, as weather early in the fiscal year impaired our ability to harvest. However, the price of one of our core products, black cherry veneer logs, increased by 3 percent from last year, and we expect this upward trend will continue. Another attractive trait of this business segment is that, while our prices are somewhat sensitive to market changes, they are nowhere near as volatile as those for lumber used in the building materials industry.

We began a facility upgrade that will help optimize the lumber produced, helping the Company attain higher margins. To take advantage of the market premium for kiln dry hardwood lumber, we added two new wood drying kilns at the Marienville Mill. The additional kiln capacity is being implemented, together with a grade, sort and stacking system, allowing us to purchase and dry additional quantities of green lumber. The project is expected to be complete in December 2007. In total, we spent nearly $4 million on these capital improvements.

**Timber Production**
(Board Feet in Millions)




Our Timber segment provides important value to our corporate structure, beyond the positive earnings impact it repeatedly achieves. On 90 percent of our timber holdings, we also have mineral rights, which allow us to explore for natural gas and oil, produce timber in a manner that creates access roads and use the land for pipeline rights-of-way as needed—all of which are integrated in, and synergistic to, our operations. In all, our timber assets not only naturally regenerate in a manner that increases the value of our holdings each year, but do so with little maintenance.

▲ NFR has partnered with the Manufacturers Association of Central New York (MACNY), a not-for-profit organization that advocates for the growth and development of New York's manufacturing sector by helping manufacturers lower costs, improve profitability and compete globally. To that end, MACNY chose NFR as its natural gas supplier for its buying consortium. Pictured from left are Jim Lalley, Senior Energy Consultant, NFR; Gwen Appelbaum, Manager, New York Sales, NFR; John Lawyer, Director of Purchasing and Technology Solutions, MACNY; and Randy Wolken, President, MACNY.

▶ This year, the Timber segment installed an automated grade, sort and stacking system and two new dry kilns at our Marienville Mill. In addition to increasing our dry kiln capacity, this new equipment makes the sawmill more cost effective.

# UNITED STATES SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# Form 10-K

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

**For the Fiscal Year Ended September 30, 2007**

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

**For the Transition Period from to**

**Commission File Number 1-3880**

# National Fuel Gas Company

*(Exact name of registrant as specified in its charter)*

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

**(716) 857-7000**
**Registrant's telephone number, including area code**

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**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 ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☑

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 ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐

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

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $3,540,898,000 as of March 31, 2007.

Common Stock, $1 Par Value, outstanding as of October 31, 2007: 83,473,107 shares.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders are incorporated by reference into Part III of this report.

# Glossary of Terms

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

***National Fuel Gas Companies***

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

**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

**NTSB** National Transportation Safety Board

**NYDEC** New York State Department of Environmental Conservation

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

**PaPUC** Pennsylvania Public Utility Commission

**SEC** Securities and Exchange Commission

***Other***

**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)

**Bcfe (or Mcfe) — represents Bcf (or Mcf) Equivalent** The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. National Fuel uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.

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

**Btu** British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.

**Capital expenditure** Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.

**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.

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

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

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

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

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

**FIN** FASB Interpretation Number

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

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

**Firm transportation and/or storage** The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.

**GAAP** Accounting principles generally accepted in the United States of America

**Goodwill** An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.

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

**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."

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

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

**PRP** Potentially responsible party

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

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

**Reserves** The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.

**Restructuring** Generally referring to partial "deregulation" of the utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or "unbundled") of gas commodity service from transportation service for wholesale and large- volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.

**SAR** Stock-settled stock appreciation right

**SFAS** Statement of Financial Accounting Standards

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

**SFAS 43** Statement of Financial Accounting Standards No. 43, Accounting for Compensated Absences

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

**Spot gas purchases** The purchase of natural gas on a short-term basis.

**Stock acquisitions** Investments in corporations.

**Unbundled service** A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.

**VEBA** Voluntary Employees' Beneficiary Association

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

**For the Fiscal Year Ended September 30, 2007**

## 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, statements regarding future prospects, plans, performance and capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will," and "may" and similar expressions.

# PART I

## Item 1 *Business*

### The Company and its Subsidiaries

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

The Company is a diversified energy company 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 725,000 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. Supply Corporation is in the process of shutting down one of its smallest storage fields, which accounts for less than one percent of its marketable storage capacity. Empire, an intrastate pipeline company acquired by the Company in February 2003, 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. Empire is constructing the Empire Connector project, which consists of a compressor station and a 78-mile pipeline extension from near Rochester, New York to an interconnection near Corning, New York with the unaffiliated Millennium Pipeline, which is also under construction. The Millennium Pipeline is expected to serve the New York City area upon its completion. Upon completion of the Empire and Millennium construction projects, which is currently expected to occur in November 2008, the Company expects that Empire will become an interstate pipeline company and will merge into Empire Pipeline, Inc. as described below.

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

In 2007, Seneca sold its subsidiary, Seneca Energy Canada Inc. (SECI), which conducted Exploration and Production operations in the provinces of Alberta, Saskatchewan and British Columbia in Canada. At September 30, 2007, the Company had U.S. reserves of 47,586 Mbbl of oil and 205,389 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.

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, 2007, the Company owned 103,700 acres of timber property and managed an additional 3,105 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 2007.

### Rates and Regulation

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

The Utility segment's rates, services and other matters are regulated by the NYPSC with respect to services provided within New York and by the PaPUC with respect to services provided within Pennsylvania. For additional discussion of the Utility segment's rates and regulation, see Item 7, MD&A under the heading "Rate and Regulatory Matters" and Item 8 at Note C-Regulatory Matters.

The Pipeline and Storage segment's rates, services and other matters are currently regulated by the FERC with respect to Supply Corporation and by the NYPSC with respect to Empire. The FERC has authorized Empire to construct and operate additional facilities (the Empire Connector project) and to become a FERC-regulated interstate pipeline company upon placement of those facilities into service, which is currently expected to occur in November 2008. For additional discussion of the Pipeline and Storage segment's rates and regulation, see Item 7, MD&A under the heading "Rate and Regulatory Matters" and Item 8 at Note C-Regulatory Matters. For further discussion of the Empire Connector project, refer to Item 7, MD&A under the headings "Investing Cash Flow" and "Rate and Regulatory Matters."

The discussion under Item 8 at Note C-Regulatory Matters includes a description of the regulatory assets and liabilities reflected on the Company's Consolidated Balance Sheets in accordance with applicable accounting standards. To the extent that the criteria set forth in such accounting standards are not met by the operations of the Utility segment or the Pipeline and Storage segment, as the case may be, the related regulatory assets and liabilities would be eliminated from the Company's Consolidated Balance Sheets and such accounting treatment would be discontinued.

In addition, the Company and its subsidiaries are subject to the same federal, state and local (including foreign) regulations on various subjects, including environmental matters, to which other companies doing similar business in the same locations are subject.

### The Utility Segment

The Utility segment contributed approximately 25.2% of the Company's 2007 income from continuing operations and 15.1% of the Company's 2007 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 28.0% of the Company's 2007 income from continuing operations and 16.7% of the Company's 2007 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. A majority of Supply Corporation's storage and transportation services is 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 2008, 66.9% of Supply Corporation's total firm storage capacity was committed under contracts that, subject to 2007 shipper or Supply Corporation notifications, could have been terminated effective in 2008. Supply Corporation received one termination notice in 2007, for a 1.5 Bcf storage contract. Termination of that contract will be effective March 31, 2008, and Supply Corporation expects to remarket that capacity for service commencing April 1, 2008, at maximum tariff rates. The strong demand for market-area storage enabled Supply Corporation to eliminate its remaining storage service rate discounts in 2007. Supply Corporation anticipates that, effective April 1, 2008, all of its storage services will be contracted at the maximum tariff rates.

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 2,001 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,093 MDth per day or 54.6% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 100 MDth per day or 5.0% of contracted transportation capacity. The remaining 808 MDth or 40.4% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2008, 58.0% of Supply Corporation's contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2008 or, subject to 2007 shipper or Supply Corporation notifications, could have been terminated effective in 2008. Based on contract expirations and termination notices received in 2007 for 2008 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to decrease 2.5% in 2008. Similarly, 24.3% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2008 or, subject to 2007 shipper or Supply Corporation notifications, could have been terminated effective in 2008. Based on contract expirations and termination notices received in 2007 for 2008 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to increase 2.1% in 2008. Supply Corporation previously has been successful in marketing and obtaining executed contracts for available transportation capacity (at discounted rates when necessary), and expects this success to continue.

Empire has service agreements for the 2007-2008 winter period for all of its firm transportation capacity, which totals approximately 565 MDth per day. Empire provides service under both annual contracts (service 12 months per year; contract term one or more years) and seasonal contracts (service during winter or summer only; contract term one or more partial years). Approximately 90.8% of Empire's firm contracted capacity is under multi-year annual contracts that expire after 2008. Approximately 2.7% of Empire's firm contracted capacity is under multi-year seasonal contracts that expire after 2008. The remaining capacity, which represents 6.5% of Empire's firm contracted capacity, is under single season or annual contracts which will expire before the end of 2008. 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 7.7% of Empire's firm contracted capacity, and the Energy Marketing segment accounts for approximately 2.0% of Empire's firm contracted capacity, with the remaining 90.3% 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 37.1% of the Company's 2007 income from continuing operations and 62.4% of the Company's 2007 net income available for common stock.

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

### The Energy Marketing Segment

The Energy Marketing segment contributed approximately 3.8% of the Company's 2007 income from continuing operations and 2.3% of the Company's 2007 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 1.9% of the Company's 2007 income from continuing operations and 1.1% of the Company's 2007 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.

### All Other Category and Corporate Operations

The All Other category and Corporate operations contributed approximately 4.0% of the Company's 2007 income from continuing operations and 2.4% of the Company's 2007 net income available for common stock.

Additional discussion of the All Other category and Corporate operations appears below in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

### Discontinued Operations

In August 2007, Seneca sold all of the issued and outstanding shares of SECI. SECI's operations are presented in the Company's financial statements as discontinued operations.

In July 2005, Horizon B.V. sold its entire 85.16% interest in United Energy, a.s. (U.E.), a district heating and electric generation business in the Czech Republic. United Energy's operations are presented in the Company's financial statements as discontinued operations.

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

### Sources and Availability of Raw Materials

Natural gas is the principal raw material for the Utility segment. In 2007, the Utility segment purchased 79.6 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 85% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 15% of the Utility segment's 2007 purchases. Purchases from Chevron Natural Gas (21%), ConocoPhillips Company (15%) and Total Gas & Power North America Inc. (14%) accounted for 50% of the Utility's 2007 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2007.

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. Forty-nine percent of the timber processed during 2007 in Highland's sawmill operations came from land owned by the Company's subsidiaries, and 51% came from outside sources. Timber cut for gas well drilling locations, access roads, and pipelines constituted an increasing portion of Highland's timber supply, both from land owned by the Company's subsidiaries and from outside sources. In addition, Highland purchased approximately 6.5 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 2007, this segment purchased 53 Bcf of natural gas, of which 51 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, 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. A decision by the PaPUC on retail competition matters remains pending.

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

### Competition: The Pipeline and Storage Segment

Supply Corporation competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and with other companies providing gas storage services. Supply Corporation has some unique characteristics which enhance its competitive position. Its facilities are located adjacent to Canada and the northeastern United States and provide part of the link between gas-consuming regions of the eastern United States and gas-producing regions of Canada and the southwestern, southern and other continental regions of the United States. This location offers the opportunity for increased transportation and storage services in the future.

Empire competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and upstate New York in particular. Empire is well situated to provide transportation from Canadian sourced gas, and its facilities are readily expandable. These characteristics provide Empire the opportunity to compete for an increased share of the gas transportation markets. As noted above, Empire is constructing the Empire Connector project, which will expand its natural gas pipeline and enable Empire to serve new markets in New York and elsewhere in the Northeast. For further discussion of this project, refer to Item 7, MD&A under the headings "Investing Cash Flow" and "Rate and Regulatory Matters."

**Competition: The Exploration and Production Segment**

The Exploration and Production segment competes with other oil and natural gas producers and marketers with respect to sales of oil and natural gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other oil and natural gas producers with respect to exploration and development prospects.

To compete in this environment, Seneca originates and acts as operator on certain of its prospects, seeks to minimize the risk of exploratory efforts through partnership-type arrangements, utilizes technology for both exploratory studies and drilling operations, and seeks market niches based on size, operating expertise and financial criteria.

**Competition: The Energy Marketing Segment**

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy 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, which can have a moderate effect on its revenues. Empire's allowed rates currently are based on a modified fixed-variable rate design, which allows recovery of most fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover variable costs associated with actual transportation of gas, to recover return on equity, and to recover income taxes. When Empire becomes a FERC-regulated interstate pipeline company (which is currently expected to occur in November 2008), Empire's allowed rates, like Supply Corporation's, will be based on a straight fixed-variable design. Under that rate design, weather-related variations in transportation volumes will not materially affect revenues.

Variations in weather conditions materially affect the volume of gas consumed by customers of the Energy Marketing segment. Volume variations have a corresponding impact on revenues within this segment.

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

### Capital Expenditures

A discussion of capital expenditures by business segment is included in Item 7, MD&A under the heading "Investing Cash Flow."

### Environmental Matters

A discussion of material environmental matters involving the Company is included in Item 7, MD&A under the heading "Environmental Matters" and in Item 8, Note H — Commitments and Contingencies.

### Miscellaneous

The Company and its wholly owned or majority-owned subsidiaries had a total of 1,952 full-time employees at September 30, 2007. Excluding the 23 employees the Company had in its Canadian operations at SECI, this is a decrease of approximately one percent from the 1,970 employees in the Company's U.S. operations at September 30, 2006.

Agreements covering employees in collective bargaining units in New York are scheduled to expire in February 2008. The Company has reached new agreements with the local leadership of those collective bargaining units, and the members of each collective bargaining unit have either approved their respective new agreement or are scheduled to vote on their respective new agreement in December 2007. The new agreements provide for an effective date of February 2008 and an expiration date of February 2013. 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, 2007 (except as otherwise noted)(1)**

| Name and Age (as of November 15, 2007) | Current Company Positions and Other Material Business Experience During Past Five Years |
|---|---|
| Philip C. Ackerman (63) | 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 (54) | 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. |
| Ronald J. Tanski (55) | 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; 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 (49) | President of Seneca since December 2006. Prior to joining Seneca, Mr. Cabell served as Executive Vice President and General Manager of Marubeni Oil & Gas (USA) Inc., an exploration and production company, from June 2003 to December 2006. From January 2002 to June 2003, Mr. Cabell served as a consultant assisting oil companies in upstream acquisition and divestment transactions as well as Gulf of Mexico entry strategy, first as an independent consultant and then as Vice President of Randall & Dewey, Inc., a major oil and gas transaction advisory firm. Mr. Cabell's prior employers are not subsidiaries or affiliates of the Company. |
| Karen M. Camiolo (48) | 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 (54) | Secretary of the Company since October 1995; Secretary of Distribution Corporation since September 1999; Senior Vice President of Distribution Corporation since July 2001. |
| Paula M. Ciprich (47) | General Counsel of the Company since January 2005; Assistant Secretary of Distribution Corporation since February 1997. |
| Donna L. DeCarolis (48) | Vice President Business Development of the Company since October 2007. Ms. DeCarolis previously served as President of NFR from January 2005 to October 2007; Secretary of NFR from March 2002 to October 2007; and Vice President of NFR from May 2001 to January 2005. |
| John R. Pustulka (55) | Senior Vice President of Supply Corporation since July 2001. |
| James D. Ramsdell (52) | Senior Vice President of Distribution Corporation since July 2001. |

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

## Item 1A *Risk Factors*

***As a holding company, National Fuel depends on its operating subsidiaries to meet its financial obligations.***

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

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

In addition to its longer term debt that is issued to the public under its indentures, National Fuel relies upon shorter term bank borrowings and commercial paper to finance a portion of its operations. National Fuel is dependent on these capital sources to provide capital to its subsidiaries to allow them to acquire, maintain and develop their properties. The availability and cost of these credit sources is cyclical and these capital sources may not remain available to National Fuel or National Fuel may not be able to obtain money at a reasonable cost in the future. National Fuel's ability to borrow under its credit facilities and commercial paper agreements depends on National Fuel's compliance with its obligations under the facilities and agreements. In addition, all of National Fuel's short-term bank loans are in the form of floating rate debt or debt that may have rates fixed for very short periods of time. At present, National Fuel has no active interest rate hedges in place to protect against interest rate fluctuations on short-term bank debt. In addition, the interest rates on National Fuel's short-term bank loans and the ability of National Fuel to issue commercial paper are affected by its debt credit ratings published by Standard & Poor's Ratings Service, 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, to permit consumer choice of natural gas suppliers. The early programs instituted to comply with the Act have not resulted in significant change, and many residential customers currently continue to purchase natural gas from the utility companies. In October 2005, the PaPUC concluded that "effective competition" does not exist in the retail natural gas supply market statewide. 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, and customer choice activities increased in Distribution Corporation's New York service territory. In April 2007, the NYPSC, noting that the retail energy marketplace in New York is established and continuing to expand, commenced a review to determine if existing programs initially designed to promote competition had outlived their usefulness and whether the cost of programs currently funded by utility rate payers should be shifted to market competitors. Increased retail choice activities, to the extent they occur, may increase Distribution Corporation's cost of doing business, put an additional portion of its business at regulatory risk, and create uncertainty for the future, all of which may make it more difficult to manage Distribution Corporation's business profitably.

In its Pipeline and Storage segment, National Fuel is subject to the jurisdiction of the FERC with respect to Supply Corporation, and to the jurisdiction of the NYPSC with respect to Empire. (The FERC has authorized Empire to construct and operate additional facilities (the Empire Connector project). When Empire completes construction and commences operations of the Empire Connector, Empire will at that time become a FERC-regulated pipeline company.) The FERC and the NYPSC, among other things, approve the rates that Supply Corporation and Empire, respectively, may charge to their natural gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. State commissions can also petition the FERC to investigate whether Supply Corporation's rates are still just and reasonable, and if not, to reduce those rates prospectively. If Supply Corporation or Empire is required in a rate proceeding to reduce the rates it charges its natural gas transportation and/or storage customers, or if Supply Corporation or Empire is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's or Empire's earnings may decrease.

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

Tariff rate schedules in each of the Utility segment's service territories contain purchased gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased gas. Assuming those rate adjustments are granted, increases in the cost of purchased gas have no direct impact on profit margins. Nevertheless, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of National Fuel's capital resources. National Fuel has issued commercial paper and used short-term borrowings in the past to temporarily finance storage inventories and purchased gas costs, and although National Fuel expects to do so in the future, it may not be able to access the markets for such borrowings at attractive interest rates or at all. Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased gas. Due to the nature of the regulatory process, there is a risk of a disallowance of full recovery of these costs during any period in which there has been a substantial upward spike in these costs. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings. In addition, even when Distribution Corporation is allowed full recovery of these purchased gas costs, during periods when natural gas prices are significantly higher than historical levels, customers may have trouble paying the resulting higher bills, and Distribution Corporation's bad debt expenses may increase and ultimately reduce earnings.

***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 exploration and production activity National Fuel otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.

***National Fuel has significant transactions involving price hedging of its oil and natural gas production as well as its fixed price purchase and sale commitments.***

In order to protect itself to some extent against unusual price volatility and to lock in fixed pricing on oil and natural gas production for certain periods of time, National Fuel periodically enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may at any time cover as much as approximately 80% of National Fuel's expected energy production during the upcoming 12-month period. These contracts reduce exposure to subsequent price drops but can also limit National Fuel's ability to benefit from increases in commodity prices. In addition, the Energy Marketing segment enters into certain hedging arrangements, primarily with respect to its fixed price purchase and sales commitments and its volumes of gas stored underground. National Fuel's Pipeline and Storage segment enters into hedging arrangements with respect to certain sales of efficiency gas, and the All Other category has hedging arrangements in place with respect to certain volumes of landfill gas committed for sale.

Under the applicable accounting rules, the Company's hedging arrangements are subject to quarterly effectiveness tests. Inherent within those effectiveness tests are assumptions concerning the long-term price differential between different types of crude oil, assumptions concerning the difference between published natural gas price indexes established by pipelines in which hedged natural gas production is delivered and the reference price established in the hedging arrangements, assumptions regarding the levels of production that will be achieved and, with regard to fixed price commitments, assumptions regarding the creditworthiness of certain customers and their forecasted consumption of natural gas. Depending on market conditions for natural gas and crude oil and the levels of production actually achieved, it is possible that certain of those assumptions may change in the future, and, depending on the magnitude of any such changes, it is possible that a portion of the Company's hedges may no longer be considered highly effective. In that case, gains or losses from the ineffective derivative financial instruments would be marked-to-market on the income statement without regard to an underlying physical transaction. Gains would occur to the extent that 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. These parties might not be able to perform their obligations under the hedge arrangements.

It is National Fuel's policy that the use of commodity derivatives contracts comply with various restrictions in effect in respective business segments. For example, in the Exploration and Production segment, commodity derivatives contracts must be confined to the price hedging of existing and forecast production, and in the Energy Marketing segment, commodity derivatives with respect to fixed price purchase and sales commitments must be matched against commitments reasonably certain to be fulfilled. Similar restrictions apply in the Pipeline and Storage segment and the All Other category. National Fuel maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose National Fuel to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of oil and natural gas falls short of hedged forecast production, the Company may incur substantial losses to cover its hedges.

***You should not place undue reliance on reserve information because such information represents estimates.***

This Form 10-K contains estimates of National Fuel's proved oil and natural gas reserves and the future net cash flows from those reserves that were prepared by National Fuel's petroleum engineers and audited by independent petroleum engineers. Petroleum engineers consider many factors and make assumptions in estimating National Fuel's oil and natural gas reserves and future net cash flows. These factors include: historical production from the area compared with production from other producing areas; the assumed effect of governmental regulation; and assumptions concerning oil and natural gas prices, production and development costs, severance and excise taxes, and capital expenditures. Lower oil and natural gas prices generally cause estimates of proved reserves to be lower. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to National Fuel's reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of National Fuel's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

If conditions remain constant, then National Fuel is reasonably certain that its reserve estimates represent economically recoverable oil and natural gas reserves and future net cash flows. If conditions change in the future, then subsequent reserve estimates may be revised accordingly. You should not assume that the present value of future net cash flows from National Fuel's proved reserves is the current market value of National Fuel's estimated oil and natural gas reserves. In accordance with SEC requirements, National Fuel bases the estimated discounted future net cash flows from its proved reserves on prices and costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of National Fuel's reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to National Fuel's 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 and abandonment expenditures, and the price received for the production.

***The amount and timing of actual future oil and natural gas production and the cost of drilling are difficult to predict and may vary significantly from reserves and production estimates, which may reduce National Fuel's earnings.***

There are many risks in developing oil and natural gas, including numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of National Fuel's Exploration and Production segment depends on its ability to develop additional oil and natural gas reserves that are economically recoverable, and its failure to do so may reduce National Fuel's earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. National Fuel's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, geology, and other factors. Drilling for oil and natural gas can be unprofitable, not only from 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 (as adjusted for hedging). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require National Fuel to recognize an immediate expense in that quarter, and its earnings would be reduced. National Fuel's Exploration and Production segment last recorded an impairment charge under the full cost method of accounting in 2006. Because of the variability in National Fuel's investment in oil and natural gas properties and the volatile nature of commodity prices, National Fuel cannot predict when in the future it may again be affected by such an impairment calculation.

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

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

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

National Fuel's operations in its various segments are subject to inherent hazards and risks such as: fires; natural disasters; explosions; geological formations with abnormal pressures; blowouts during well drilling; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage, environmental damage or business interruption losses. Additionally, National Fuel's facilities, machinery, and equipment may be subject to sabotage. Any of these events could cause a loss of hydrocarbons, environmental pollution, claims for personal injury, death, property damage or business interruption, or governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, National Fuel maintains insurance coverage against some, but not all, potential losses. In addition, many of the agreements that National Fuel executes with contractors provide for the division of responsibilities between the contractor and National Fuel, and National Fuel seeks to obtain an indemnification from the contractor for certain of these risks. National Fuel is not always able, however, to secure written agreements with its contractors that contain indemnification, and sometimes National Fuel is required to indemnify others.

Insurance or indemnification agreements when obtained may not adequately protect National Fuel against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, the imposition of fines, penalties or mandated programs by governmental authorities, the failure of a contractor to meet its indemnification obligations, or the failure of an insurance company to pay valid claims could result in substantial losses to National Fuel. In addition, insurance may not be available, or if available may not be adequate, to cover any or all of these risks. It is also possible that insurance premiums or other costs may rise significantly in the future, so as to make such insurance prohibitively expensive.

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

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

***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 net investment of the Company in property, plant and equipment was $2.9 billion at September 30, 2007. Approximately 62% of this investment was in the Utility and Pipeline and Storage segments, which are primarily located in western and central New York and northwestern Pennsylvania. The Exploration and Production segment, which has the next largest investment in net property, plant and equipment (34%), is primarily located in California, in the Appalachian region of the United States, in Wyoming, and in the Gulf Coast region of Texas, Louisiana, and Alabama. The remaining net investment in property, plant and equipment consisted of the Timber segment (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 $33.7 million, or 1.2%, since 2002. During 2007, the Company sold SECI, Seneca's wholly owned subsidiary that operated in Canada. The net property, plant and equipment of SECI at the date of sale was $107.7 million. In addition, during 2005, the Company sold its majority interest in U.E., a district heating and electric generation business in the Czech Republic. The net property, plant and equipment of U.E. at the date of sale was $223.9 million.

The Utility segment had a net investment in property, plant and equipment of $1.1 billion at September 30, 2007. The net investment in its gas distribution network (including 14,813 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, 2007.

The Pipeline and Storage segment had a net investment of $681.9 million in property, plant and equipment at September 30, 2007. Transmission pipeline represents 33% of this segment's total net investment and includes 2,495 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 441 miles of pipeline. Net investment in storage facilities includes $89.8 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 75,404 installed compressor horsepower that represent 14% 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 $982.7 million at September 30, 2007.

The Timber segment had a net investment in property, plant and equipment of $89.9 million at September 30, 2007. Located primarily in northwestern Pennsylvania, the net investment includes two sawmills, 103,700 acres of land and timber, and 3,105 acres of timber rights.

The Utility and Pipeline and Storage segments' facilities provided the capacity to meet the Company's 2007 peak day sendout, including transportation service, of 1,743 MMcf, which occurred on February 5, 2007. Withdrawals from storage of 779.3 MMcf provided approximately 44.7% of the requirements on that day.

Company maps are included in exhibit 99.2 of this Form 10-K and are incorporated herein by reference.

### Exploration and Production Activities

The Company is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, in Wyoming, and in the Gulf Coast region of Texas, Louisiana, and Alabama. Also, Exploration and Production operations were conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada, until the sale of these properties on August 31, 2007. Further discussion of the sale of the Canadian oil and gas properties is included in Item 8, Note-I-Discontinued Operations. Further discussion of oil and gas producing activities is included in Item 8, Note O-Supplementary Information for Oil and Gas Producing Activities. Note O sets forth proved developed and undeveloped reserve information for Seneca. Seneca's proved developed and undeveloped natural gas reserves decreased from 233 Bcf at September 30, 2006 to 205 Bcf at September 30, 2007. This decrease is attributed primarily to the sale of the Canadian gas properties (40.1 Bcf) and production of 26.3 Bcf. These decreases were partially offset by extensions and discoveries of 34.6 Bcf, primarily in the Appalachian region (29.7 Bcf). Seneca's proved developed and undeveloped oil reserves decreased from 58,018 Mbbl at September 30, 2006 to 47,586 Mbbl at September 30, 2007. This decrease is attributed to revisions of previous estimates (5,963 Mbbl), primarily occurring in California, production (3,450 Mbbl) and the sale of the Canadian oil properties (1,458 Mbbl). 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 is 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 is attributed mostly to production.

Seneca's oil and gas reserves reported in Item 8 at Note O as of September 30, 2007 were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Seneca reports its oil and gas reserve information on an annual basis to the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy. The oil and gas reserve information reported to the EIA showed 211 Bcf and 59,246 Mbbl of gas and oil reserves, respectively, which differs from the reserve information summarized in Item 8 at Note O. The reasons for this difference are as follows: (a) reserves are reported to the EIA on a calendar year basis, while reserves disclosed in Item 8 at Note O are shown on a fiscal year basis; (b) reserves reported to the EIA include only properties operated by Seneca, while reserves disclosed in Item 8 at Note O included both Seneca operated properties and non-operated properties in which Seneca has an interest; and (c) reserves are reported to the EIA on a gross basis verses the reserves disclosed in Item 8 at Note O, which are reported on a net revenue interest basis.

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 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **United States** | | | |
| Gulf Coast Region | | | |
| Average Sales Price per Mcf of Gas | $ 6.58 | $ 8.01 | $ 7.05 |
| Average Sales Price per Barrel of Oil | $63.04 | $64.10 | $49.78 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 6.87 | $ 5.89 | $ 6.01 |
| Average Sales Price per Barrel of Oil (after hedging) | $64.09 | $47.46 | $35.03 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.08 | $ 0.86 | $ 0.71 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 40 | 36 | 50 |
| West Coast Region | | | |
| Average Sales Price per Mcf of Gas | $ 6.54 | $ 7.93 | $ 6.85 |
| Average Sales Price per Barrel of Oil | $56.86 | $56.80 | $42.91 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 6.82 | $ 7.19 | $ 6.15 |
| Average Sales Price per Barrel of Oil (after hedging) | $47.43 | $37.69 | $23.01 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.54 | $ 1.35 | $ 1.15 |

| | For The Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 50 | 53 | 53 |
| Appalachian Region | | | |
| Average Sales Price per Mcf of Gas | $ 7.48 | $ 9.53 | $ 7.60 |
| Average Sales Price per Barrel of Oil | $62.26 | $65.28 | $48.28 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 8.25 | $ 8.90 | $ 7.01 |
| Average Sales Price per Barrel of Oil (after hedging) | $62.26 | $65.28 | $48.28 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 0.69 | $ 0.69 | $ 0.63 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 17 | 15 | 13 |
| **Total United States** | | | |
| Average Sales Price per Mcf of Gas | $ 6.82 | $ 8.42 | $ 7.13 |
| Average Sales Price per Barrel of Oil | $58.43 | $58.47 | $44.87 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 7.25 | $ 7.02 | $ 6.26 |
| Average Sales Price per Barrel of Oil (after hedging) | $51.68 | $40.26 | $26.59 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.23 | $ 1.09 | $ 0.90 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 108 | 104 | 117 |
| **Canada — Discontinued Operations** | | | |
| Average Sales Price per Mcf of Gas | $ 6.09 | $ 7.14 | $ 6.15 |
| Average Sales Price per Barrel of Oil | $50.06 | $51.40 | $42.97 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 6.17 | $ 7.47 | $ 6.14 |
| Average Sales Price per Barrel of Oil (after hedging) | $50.06 | $51.40 | $42.97 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.94 | $ 1.57 | $ 1.29 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 21 | 26 | 27 |
| **Total Company** | | | |
| Average Sales Price per Mcf of Gas | $ 6.64 | $ 8.04 | $ 6.86 |
| Average Sales Price per Barrel of Oil | $57.93 | $57.94 | $44.72 |
| Average Sales Price per Mcf of Gas (after hedging) | $ 6.98 | $ 7.15 | $ 6.23 |
| Average Sales Price per Barrel of Oil (after hedging) | $51.58 | $41.10 | $27.86 |
| Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced | $ 1.35 | $ 1.18 | $ 0.98 |
| Average Production per Day (in MMcf Equivalent of Gas and Oil Produced) | 129 | 130 | 144 |

## Productive Wells

| | Gulf Coast Region | | West Coast Region | | Appalachian Region | | Total Company | |
|---|---|---|---|---|---|---|---|---|
| At September 30, 2007 | Gas | Oil | Gas | Oil | Gas | Oil | Gas | Oil |
| Productive Wells — Gross | 33 | 37 | — | 1,313 | 2,347 | 7 | 2,380 | 1,357 |
| Productive Wells — Net | 19 | 16 | — | 1,305 | 2,274 | 6 | 2,293 | 1,327 |

### Developed and Undeveloped Acreage

| At September 30, 2007 | Golf Coast Region | West Coast Region | Appalachian Region | Total Company |
|---|---|---|---|---|
| Developed Acreage | | | | |
| — Gross | 141,425 | 11,058 | 515,400 | 667,883 |
| — Net | 97,756 | 10,688 | 488,907 | 597,351 |
| Undeveloped Acreage | | | | |
| — Gross | 148,960 | — | 472,407 | 621,367 |
| — Net | 89,921 | — | 447,802 | 537,723 |

As of September 30, 2007, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 23,332 acres in 2008 (12,707 net acres), 38,741 acres in 2009 (23,219 net acres), 23,038 acres in 2010 (11,491 net acres), and 536,256 acres thereafter (490,306 net acres).

### Drilling Activity

| | Productive | | | Dry | | |
|---|---|---|---|---|---|---|
| For the Year Ended September 30 | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| **United States** | | | | | | |
| Gulf Coast Region | | | | | | |
| Net Wells Completed | | | | | | |
| — Exploratory | 1.31 | 2.94 | 1.30 | 1.42 | 0.85 | 0.47 |
| — Development | 1.00 | 0.78 | 0.23 | 0.67 | — | — |
| West Coast Region | | | | | | |
| Net Wells Completed | | | | | | |
| — Exploratory | 0.50 | — | — | — | — | — |
| — Development | 58.99 | 92.98 | 116.97 | 2.00 | 1.00 | — |
| Appalachian Region | | | | | | |
| Net Wells Completed | | | | | | |
| — Exploratory | 8.10 | 3.88 | 3.00 | — | — | 4.00 |
| — Development | 184.00 | 140.58 | 45.00 | 2.00 | 1.75 | 1.00 |
| Total United States | | | | | | |
| Net Wells Completed | | | | | | |
| — Exploratory | 9.91 | 6.82 | 4.30 | 1.42 | 0.85 | 4.47 |
| — Development | 243.99 | 234.34 | 162.20 | 4.67 | 2.75 | 1.00 |
| **Canada — Discontinued Operations** | | | | | | |
| Net Wells Completed | | | | | | |
| — Exploratory | 6.38 | 12.60 | 21.14 | — | 1.35 | 2.00 |
| — Development | 1.80 | 2.50 | 3.50 | — | 1.00 | — |
| **Total** | | | | | | |
| Net Wells Completed | | | | | | |
| — Exploratory | 16.29 | 19.42 | 25.44 | 1.42 | 2.20 | 6.47 |
| — Development | 245.79 | 236.84 | 165.70 | 4.67 | 3.75 | 1.00 |

**Present Activities**

| At September 30, 2007 | Gulf Coast Region | West Coast Region | Appalachian Region | Total Company |
|---|---|---|---|---|
| Wells in Process of Drilling(1) | | | | |
| — Gross | 2.00 | 4.00 | 90.00 | 96.00 |
| — Net | 1.30 | 4.00 | 88.00 | 93.30 |

(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 failure to initiate natural gas service, despite an attempt to do so, at an apartment leased 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. Trial was scheduled to begin October 15, 2007. However, the parties resolved the action.

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."

On November 8, 2007, Distribution Corporation filed a complaint with the PaPUC requesting that the PaPUC commence an investigation to determine whether New Mountain Vantage GP, L.L.C. (New Mountain), and others acting in concert with it, have violated Pennsylvania law by acquiring control of Distribution Corporation without the prior approval of the PaPUC. In the event the PaPUC finds that New Mountain and others acting in concert with it have not yet acquired control of Distribution Corporation, Distribution Corporation petitioned the PaPUC for an order requiring New Mountain to show cause why it should not be required to apply for and receive a certificate of public convenience prior to acquiring control of Distribution Corporation, and requiring that the certificate of public convenience be obtained prior to any vote of stockholders of the Company which could result in the acquisition of control over Distribution Corporation. According to a November 6, 2007 filing with the SEC, New Mountain and certain other holders acknowledging acting with New Mountain as part of a group for purposes of the federal securities laws collectively own 9.7% of the outstanding shares of the Company. Distribution Corporation alleges in its filing with the PaPUC that New Mountain and others acting in concert with it have acquired or are seeking to acquire control of the Company, which results or would result in the acquisition of indirect control over Distribution Corporation. On November 21, 2007, New Mountain filed preliminary objections to Distribution Corporation's complaint and petition and requested that the PaPUC rule on the preliminary objections at its December 20, 2007 public meeting. In addition, two agencies of the Commonwealth of Pennsylvania, the Office of Consumer Advocate and the Office of Small Business Advocate, petitioned the PaPUC to intervene in the proceeding, and the Office of Small Business Advocate requested evidentiary hearings. Distribution Corporation anticipates that its response to New Mountain's preliminary objections will request that the PaPUC, at its December 20, 2007 public meeting, initiate an investigation by issuing an order for New Mountain to show cause why it should not be required to apply for and receive a certificate of public convenience prior to acquiring control of Distribution Corporation.

The resolution of the Fordham-Coleman action described above will not have a material effect on the consolidated financial condition, results of operations, or cash flow of the Company. The Company believes, based on the information presently known, that the ultimate resolution of the matters before the PaPUC described above 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 outcomes of those matters, and it is possible that the outcomes could be material to the consolidated financial condition, results of operations or cash flow of the Company.

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

In addition to 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, 2007.

## PART II

### Item 5 *Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Information regarding the market for the Company's common equity and related stockholder matters appears under Item 12 at Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters, Item 8 at Note E-Capitalization and Short-Term Borrowings and Note N-Market for Common Stock and Related Shareholder Matters (unaudited).

On July 2, 2007, the Company issued a total of 2,400 unregistered shares of Company common stock to the eight 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, 2007, 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.

**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, 2007 | 7,317 | $44.75 | — | 4,278,122 |
| Aug. 1-31, 2007 | 124,254 | $41.93 | 113,000 | 4,165,122 |
| Sept. 1-30, 2007 | 22,622 | $44.97 | — | 4,165,122 |
| Total | 154,193 | $42.51 | 113,000 | 4,165,122 |

(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 7,317 in July 2007, 11,254 in August 2007 and 22,622 in September 2007 (a three-month total of 41,193). Of those shares, 23,498 were purchased for the Company's 401(k) plans and 17,695 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 | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2004 | 2003 |
| | | | (Thousands) | | |
| **Summary of Operations** | | | | | |
| Operating Revenues | $2,039,566 | $2,239,675 | $1,860,774 | $1,867,875 | $1,821,899 |
| Operating Expenses: | | | | | |
| Purchased Gas | 1,018,081 | 1,267,562 | 959,827 | 949,452 | 963,567 |
| Operation and Maintenance | 396,408 | 395,289 | 388,094 | 374,010 | 330,316 |
| Property, Franchise and Other Taxes | 70,660 | 69,202 | 68,164 | 68,378 | 72,073 |
| Depreciation, Depletion and Amortization | 157,919 | 151,999 | 156,502 | 159,184 | 154,634 |
| | 1,643,068 | 1,884,052 | 1,572,587 | 1,551,024 | 1,520,590 |
| Gain (Loss) on Sale of Timber Properties | — | — | — | (1,252) | 168,787 |
| Operating Income | 396,498 | 355,623 | 288,187 | 315,599 | 470,096 |
| Other Income (Expense): | | | | | |
| Income from Unconsolidated Subsidiaries | 4,979 | 3,583 | 3,362 | 805 | 535 |
| Impairment of Investment in Partnership | — | — | (4,158) | — | — |
| Interest Income | 1,550 | 9,409 | 6,236 | 1,771 | 2,427 |
| Other Income | 4,936 | 2,825 | 12,744 | 2,908 | 2,204 |
| Interest Expense on Long-Term Debt | (68,446) | (72,629) | (73,244) | (82,989) | (91,381) |
| Other Interest Expense | (6,029) | (5,952) | (9,069) | (6,354) | (11,010) |
| Income from Continuing Operations Before Income Taxes | 333,488 | 292,859 | 224,058 | 231,740 | 372,871 |
| Income Tax Expense | 131,813 | 108,245 | 85,621 | 89,820 | 116,795 |
| Income from Continuing Operations | 201,675 | 184,614 | 138,437 | 141,920 | 256,076 |
| Discontinued Operations: | | | | | |
| Income (Loss) from Operations, Net of Tax | 15,479 | (46,523) | 25,277 | 24,666 | (68,240) |
| Gain on Disposal, Net of Tax | 120,301 | — | 25,774 | — | — |
| Income (Loss) from Discontinued Operations, Net of Tax | 135,780 | (46,523) | 51,051 | 24,666 | (68,240) |

| | Year Ended September 30 | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2004 | 2003 |
| | | | (Thousands) | | |
| Income Before Cumulative Effect of Changes in Accounting | 337,455 | 138,091 | 189,488 | 166,586 | 187,836 |
| Cumulative Effect of Changes in Accounting | — | — | — | — | (8,892) |
| Net Income Available for Common Stock | $ 337,455 | $ 138,091 | $ 189,488 | $ 166,586 | $ 178,944 |
| **Per Common Share Data** | | | | | |
| Basic Earnings from Continuing Operations per Common Share | $ 2.43 | $ 2.20 | $ 1.66 | $ 1.73 | $ 3.17 |
| Diluted Earnings from Continuing Operations per Common Share | $ 2.37 | $ 2.15 | $ 1.63 | $ 1.71 | $ 3.15 |
| Basic Earnings per Common Share(2) | $ 4.06 | $ 1.64 | $ 2.27 | $ 2.03 | $ 2.21 |
| Diluted Earnings per Common Share(2) | $ 3.96 | $ 1.61 | $ 2.23 | $ 2.01 | $ 2.20 |
| Dividends Declared | $ 1.22 | $ 1.18 | $ 1.14 | $ 1.10 | $ 1.06 |
| Dividends Paid | $ 1.21 | $ 1.17 | $ 1.13 | $ 1.09 | $ 1.05 |
| Dividend Rate at Year-End | $ 1.24 | $ 1.20 | $ 1.16 | $ 1.12 | $ 1.08 |
| At September 30: | | | | | |
| **Number of Registered Shareholders** | 16,989 | 17,767 | 18,369 | 19,063 | 19,217 |
| **Net Property, Plant and Equipment** | | | | | |
| Utility | $1,099,280 | $1,084,080 | $1,064,588 | $1,048,428 | $1,028,393 |
| Pipeline and Storage | 681,940 | 674,175 | 680,574 | 696,487 | 705,927 |
| Exploration and Production(3) | 982,698 | 1,002,265 | 974,806 | 923,730 | 925,833 |
| Energy Marketing | 102 | 59 | 97 | 80 | 171 |
| Timber | 89,902 | 90,939 | 94,826 | 82,838 | 87,600 |
| All Other | 16,735 | 17,394 | 18,098 | 21,172 | 22,042 |
| Corporate(4) | 7,748 | 8,814 | 6,311 | 234,029 | 221,082 |
| Total Net Plant | $2,878,405 | $2,877,726 | $2,839,300 | $3,006,764 | $2,991,048 |
| **Total Assets** | $3,888,412 | $3,763,748 | $3,749,753 | $3,738,103 | $3,740,944 |
| **Capitalization** | | | | | |
| Comprehensive Shareholders' Equity | $1,630,119 | $1,443,562 | $1,229,583 | $1,253,701 | $1,137,390 |
| Long-Term Debt, Net of Current Portion | 799,000 | 1,095,675 | 1,119,012 | 1,133,317 | 1,147,779 |
| Total Capitalization | $2,429,119 | $2,539,237 | $2,348,595 | $2,387,018 | $2,285,169 |

(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 SECI discontinued operations as follows: $0 for 2007, $88,023 for 2006, $170,929 for 2005, $142,860 for 2004, and $116,487 for 2003.

(4) Includes net plant of the former international segment as follows: $38 for 2007, $27 for 2006, $20 for 2005, $227,905 for 2004, and $219,199 for 2003.

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

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, "Results of Operations;"
3. Operating, investing and financing cash flows under the heading "Capital Resources and Liquidity;"
4. Off-Balance Sheet Arrangements;
5. Contractual Obligations; and
6. Other Matters, including: (a) 2007 and 2008 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 2007, and the main reason for the significant earnings increase over 2006, was the Company's sale of SECI, Seneca's wholly owned subsidiary that operated in Canada. SECI was engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in the provinces of Alberta, Saskatchewan and British Columbia in Canada. This sale resulted in a $120.3 million gain, net of tax. The decision to sell SECI was based on lower than expected returns from the Canadian oil and gas properties combined with difficulty in finding significant new reserves. As a result of the decision to sell SECI, the Company began presenting all SECI operations as discontinued operations in September 2007. Also contributing to the increase in earnings over 2006 was the non-recurrence of impairment charges of $68.6 million related to the Exploration and Production segment's Canadian oil and gas assets recognized during 2006 under the full cost method of accounting, which is discussed below under Critical Accounting Estimates. Seneca intends to continue its exploration and development activities in the Gulf of Mexico, in California and in Appalachia, subject to regular re-evaluation of its efforts and opportunities in each region.

The Company spent $247.6 million on capital expenditures related to continuing operations during 2007, with approximately 59% being spent in the Exploration and Production segment. This was in line with the Company's expectations. As mentioned above, Seneca will continue its exploration and development activities in Appalachia, in California and in the Gulf of Mexico. In Appalachia, drilling will be accelerated. Seneca intends to commence drilling of 280 wells for shallow tight sand targets in fiscal 2008, a 20% increase over the 233 such wells drilled in 2007. In addition, Seneca anticipates continued drilling in the deeper Marcellus Shale formation in Appalachia with its joint venture partner, EOG Resources, Inc. Seneca expects that as many as eighteen Marcellus Shale wells will be drilled on its acreage in 2008, ten of which are expected to be horizontal wells. In the Gulf of Mexico, Seneca's strategy will be to follow a focused drilling plan in the specific areas where the Company has expertise and past success.

The Company took a significant step forward this year regarding the Empire Connector project. In June 2007, Empire signed a firm transportation service agreement with KeySpan Gas East Corporation, thereby obligating Empire to provide transportation service that will require construction of the Empire Connector project. Construction of the Empire Connector began in September 2007 and 20 miles will be completed by December 2007. The Company expects to complete the project by November 1, 2008. The total cost to the Company of the Empire Connector project is estimated at $177 million, after giving effect to sales tax exemptions. The Company expects the expansion of the Pipeline and Storage segment to remain a major strategic priority. Supply Corporation has verified that there is substantial market interest in transporting gas produced in the Rocky Mountain area to the Northeast. In order to serve this anticipated demand, Supply Corporation has proposed a new 324-mile pipeline that would commence at Clarington, Ohio, the proposed terminus of the Rockies Express pipeline, and extend to the Millennium Pipeline under construction at Corning, New York. From Corning, Rocky Mountain gas will be able to get to the New York City area and to New England. The proposed pipeline would be designed to move approximately 550 to 750 MDth of gas per day, as well as accommodate volumes from local production areas. These projects are discussed further in the Capital Resources and Liquidity and Rates and Regulatory Matters sections that follow.

The Company is currently evaluating the appropriateness of establishing a Master Limited Partnership (MLP) for its pipeline and storage assets, and another MLP for certain of its exploration and production assets. If this evaluation determined that the MLP structure is sound and in the shareholders' interest, the Company would pursue the MLP structure for the appropriate Company assets. Potential impediments to establishing MLPs include: (a) the low tax basis of our pipeline and storage assets, which substantially mitigates the tax advantages of an MLP structure; (b) the highly integrated operations of the Company's Pipeline and Storage and Utility business segments; and (c) the sustainability of an exploration and production MLP given the natural decline curve of production from all oil and gas properties. As a result, new long-lived reserves must be constantly added to an exploration and production MLP in order to sustain the MLP's cash distributions. Acquisitions of long-lived reserves could be very costly given the significant premiums that are currently being paid for long-lived reserves.

The Company also began repurchasing outstanding shares of common stock during fiscal 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, 2007, the Company had repurchased 3,834,878 shares for $133.2 million under this program, including 1,308,328 shares for $48.1 million during the year ended September 30, 2007. These matters are discussed further in the Capital Resources and Liquidity section that follows.

On January 29, 2007, the Company commenced a rate case in the New York jurisdiction of the Utility segment by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by $52.0 million annually. The Company explained in the filing that its request for rate relief is necessitated by decreased revenues resulting from customer conservation efforts and increased customer uncollectibles, among other things. The rate filing also includes a proposal for an aggressive efficiency and conservation initiative with a revenue decoupling mechanism designed to render the Company indifferent to throughput reductions resulting from conservation. In September 2007, the NYPSC issued an order approving the Company's conservation program, and the administrative law judge assigned to the proceeding issued a recommended decision, which recommends a rate increase designed to provide additional annual revenues of $2.5 million as well as a bill surcharge that would collect up to $10.8 million to recover expenses arising from the conservation program. The recommended decision also recommends approval of the unopposed revenue decoupling mechanism. The NYPSC is not bound to accept the recommended decision. This matter 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 does not recognize any gain or loss on the sale or other disposition of oil and gas properties unless the gain or loss would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center.

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

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test , which is performed each quarter, determines a limit, or ceiling, on a country-by-country basis on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying current market prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions 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. These impairment charges are now included in the loss from discontinued operations for 2006 due to the sale of SECI during 2007.

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.

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

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

*Regulation.* The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to SFAS 71, and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting policies allows the Company to defer expenses and income on the balance sheet as regulatory assets and liabilities when it is probable that those expenses and income will be allowed in the ratesetting process in a period different from the period in which they would have been reflected in the income statement by an unregulated company. These deferred regulatory assets and liabilities are then flowed through the income statement in the period in which the same amounts are reflected in rates. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item. For further discussion of the Company's regulatory assets and liabilities, refer to Item 8 at Note C — Regulatory Matters.

*Accounting for Derivative Financial Instruments.* The Company, in its Exploration and Production segment, Energy Marketing segment, Pipeline and Storage segment and All Other category, uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments are categorized as price swap agreements, no cost collars and futures contracts. The Company, in its Pipeline and Storage segment, previously used an interest rate collar to limit interest rate fluctuations on certain variable rate debt. In accordance with the provisions of SFAS 133, the Company accounted for these instruments as effective cash flow hedges or fair value hedges. In 2007, the Company discontinued hedge accounting for the interest rate collar, which resulted in a gain being recognized. Gains or losses associated with the derivative financial instruments are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that the derivative financial instruments would ever be deemed to be ineffective based on the effectiveness testing, mark-to-market gains or losses from the derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction. As discussed below, the Company was required to discontinue hedge accounting for a portion of its derivative financial instruments in the Exploration and Production segment, resulting in a charge to earnings in 2005.

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The fair values of the non exchange-traded derivative financial instruments are based on valuations determined by the counterparties. 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 Company also utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments. The expected return on plan assets assumption used by the Company reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets. Changes in actuarial assumptions and actuarial experience 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 93% and 94%, 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, 2007 and 2006.

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, while the discount rate used to determine benefit obligations did not change from 2006 to 2007, the discount rate was changed from 5.0% in 2005 to 6.25% in 2006. The change in the discount rate from 2005 to 2006 reduced the pension plan projected benefit obligation by $113.1 million and the accumulated post-retirement benefit obligation by $77.5 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligations and the accumulated post-retirement benefit obligation for the Post-Retirement Plan. For 2007, 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 $68.4 million and $38.6 million, respectively. The actual versus expected benefit payments for 2007 caused a decrease of $1.3 million and $1.8 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 is 9 years for both the Retirement Plan and the Post-Retirement Plan. For further discussion of the Company's pension and other post-retirement benefits, refer to Other Matters in this Item 7, which includes a discussion of funding for the current year and the adoption of SFAS 158, and to Item 8 at Note G — Retirement Plan and Other Post Retirement Benefits.

## RESULTS OF OPERATIONS

### EARNINGS

### 2007 Compared with 2006

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

***2007 Events***

- A $120.3 million gain on the sale of SECI, which was completed in August 2007. This amount is included in earnings from discontinued operations;
- A $4.8 million benefit to earnings in the Pipeline and Storage segment due to the reversal of a reserve established for all costs incurred related to the Empire Connector project recognized during June 2007;
- A $1.9 million benefit to earnings in the Pipeline and Storage segment associated with the discontinuance of hedge accounting for Empire's interest rate collar; and
- A $2.3 million benefit to earnings in the Energy Marketing segment related to the resolution of a purchased gas contingency.

***2006 Events***

- $68.6 million of impairment charges related to the Exploration and Production segment's Canadian oil and gas assets under the full cost method of accounting using natural gas pricing at June 30, 2006 and September 30, 2006;
- An $11.2 million benefit to earnings in the Exploration and Production segment ($6.1 million in continuing operations and $5.1 million in discontinued operations) related to income tax adjustments recognized during 2006; and
- A $2.6 million benefit to earnings in the Utility segment related to the correction of Distribution Corporation's calculation of the symmetrical sharing component of New York's gas adjustment rate.

### 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 has presented its Canadian operations in the Exploration and Production segment (in conjunction with the sale of SECI) as well as for its Czech Republic operations (in conjunction with the sale of U.E.) as discontinued operations. The Company's earnings from continuing operations were $184.6 million in 2006 compared with $138.4 million in 2005. The Company recorded a loss from discontinued operations of $46.5 million in 2006 compared with earnings from discontinued operations of $51.1 million in 2005. The increase in earnings from continuing operations of $46.2 million is primarily the result of higher earnings in the Exploration and Production, Utility, Energy Marketing, and Timber segments, combined with higher earnings in the All Other category and a lower loss in the Corporate category. These were offset somewhat by lower earnings in the Pipeline and Storage segment, as shown in the table below. The loss from discontinued operations in 2006 compared to earnings from discontinued operations in 2005 reflects the recognition of $68.6 million of impairment charges in 2006 related to the Exploration and Production segment's Canadian oil and gas assets as well as the non-recurrence of the gain on the sale of U.E. recognized in 2005. Earnings from continuing operations and discontinued operations were impacted by several events discussed above and the following 2005 events:

***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.

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 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Utility | $ 50,886 | $ 49,815 | $ 39,197 |
| Pipeline and Storage | 56,386 | 55,633 | 60,454 |
| Exploration and Production | 74,889 | 67,494 | 35,581 |
| Energy Marketing | 7,663 | 5,798 | 5,077 |
| Timber | 3,728 | 5,704 | 5,032 |
| Total Reportable Segments | 193,552 | 184,444 | 145,341 |
| All Other | 2,564 | 359 | (2,616) |
| Corporate(1) | 5,559 | (189) | (4,288) |
| Total Earnings from Continuing Operations | 201,675 | 184,614 | 138,437 |
| Earnings (Loss) from Discontinued Operations | 135,780 | (46,523) | 51,051 |
| Total Consolidated | $337,455 | $138,091 | $189,488 |

(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 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Retail Revenues: | | | |
| Residential | $ 848,693 | $ 993,928 | $ 868,292 |
| Commercial | 136,863 | 166,779 | 145,393 |
| Industrial | 8,271 | 13,484 | 13,998 |
| | 993,827 | 1,174,191 | 1,027,683 |
| Off-System Sales | 9,751 | — | — |
| Transportation | 102,534 | 92,569 | 83,669 |
| Other | 14,612 | 14,003 | 5,715 |
| | $1,120,724 | $1,280,763 | $1,117,067 |

### Utility Throughput — million cubic feet (MMcf)

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| Retail Sales: | | | |
| Residential | 60,236 | 59,443 | 66,903 |
| Commercial | 10,713 | 10,681 | 11,984 |
| Industrial | 727 | 985 | 1,387 |
| | 71,676 | 71,109 | 80,274 |
| Off-System Sales | 1,355 | — | — |
| Transportation | 62,240 | 57,950 | 59,770 |
| | 135,271 | 129,059 | 140,044 |

### Degree Days

| | | | | Percent (Warmer) Colder Than | |
|---|---|---|---|---|---|
| Year Ended September 30 | | Normal | Actual | Normal | Prior Year |
| 2007: | Buffalo | 6,692 | 6,271 | (6.3)% | 5.1% |
| | Erie | 6,243 | 6,007 | (3.8)% | 5.6% |
| 2006: | Buffalo | 6,692 | 5,968 | (10.8)% | (9.4)% |
| | Erie | 6,243 | 5,688 | (8.9)% | (8.9)% |
| 2005: | Buffalo | 6,692 | 6,587 | (1.6)% | 0.2% |
| | Erie | 6,243 | 6,247 | 0.1% | 2.6% |

### 2007 Compared with 2006

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

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

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

As reported in 2006, on November 17, 2006 the U.S. Court of Appeals vacated and remanded FERC's Order No. 2004, its latest affiliate standards of conduct, with respect to natural gas pipelines. The court's decision became effective on January 5, 2007, and on January 9, 2007, FERC issued Order No. 690, its Interim Rule, designed to respond to the court's decision. In Order No. 690, as clarified by FERC on March 21, 2007, the FERC readopted, on an interim basis, certain provisions that existed prior to the issuance of Order No. 2004 that had made it possible for the Utility to engage in certain off-system sales without triggering the adverse consequences that would otherwise arise under the standards of conduct. As such, the Utility resumed engaging in off-system sales on non-affiliated pipelines as of May 2007, resulting in total off-system sales revenues of $9.8 million for 2007. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins in 2007.

**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 agreement 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 agreement 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 rate agreement 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 $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 were 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 rate 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.

### 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 $10.04 per Mcf in 2007, a decrease of 17% from the average cost of $12.07 per Mcf in 2006. The average cost of purchased gas in 2006 was 31% higher than the average cost of $9.19 per Mcf in 2005. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

### Earnings

### 2007 Compared with 2006

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

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

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

The impact of weather on the Utility segment's New York rate jurisdiction is tempered by a WNC. The WNC, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the

Utility segment's New York customers. In 2007 and 2006, the WNC preserved earnings of approximately $2.3 million and $6.2 million, respectively, as the weather was warmer than normal.

**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 agreement 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 agreement, 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.

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.

**PIPELINE AND STORAGE**

**Revenues**

**Pipeline and Storage Operating Revenues**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Firm Transportation | $118,771 | $118,551 | $117,146 |
| Interruptible Transportation | 4,161 | 4,858 | 4,413 |
| | 122,932 | 123,409 | 121,559 |
| Firm Storage Service | 66,966 | 66,718 | 65,320 |
| Interruptible Storage Service | 169 | 39 | 267 |
| | 67,135 | 66,757 | 65,587 |
| Other | 21,899 | 24,186 | 28,713 |
| | $211,966 | $214,352 | $215,859 |

**Pipeline and Storage Throughput — (MMcf)**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| Firm Transportation | 351,113 | 363,379 | 357,585 |
| Interruptible Transportation | 4,975 | 11,609 | 14,794 |
| | 356,088 | 374,988 | 372,379 |

**2007 Compared with 2006**

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

**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 efficiency gas revenues due to lower natural gas prices, a $0.7 million decrease in cashout revenues, and a $1.4 million decrease in revenue attributable to a lease termination fee adjustment (an intercompany transaction) for the Company's former headquarters. 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.

### Earnings

### 2007 Compared with 2006

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

### 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 efficiency gas revenues ($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).

## EXPLORATION AND PRODUCTION

### Revenues

### Exploration and Production Operating Revenues

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Gas (after Hedging) from Continuing Operations | $143,785 | $126,969 | $132,528 |
| Oil (after Hedging) from Continuing Operations | 167,627 | 134,307 | 94,925 |
| Gas Processing Plant from Continuing Operations | 37,528 | 42,252 | 36,350 |
| Other from Continuing Operations | 1,147 | 3,072 | (3,447) |
| Intrasegment Elimination from Continuing Operations(1) | (26,050) | (31,704) | (29,706) |
| Operating Revenues from Continuing Operations | $324,037 | $274,896 | $230,650 |
| Operating Revenues from Canada — Discontinued Operations | $ 50,495 | $ 71,984 | $ 62,775 |

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

**Production Volumes**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Gas Production** *(MMcf)* | | | |
| Gulf Coast | 10,356 | 9,110 | 12,468 |
| West Coast | 3,929 | 3,880 | 4,052 |
| Appalachia | 5,555 | 5,108 | 4,650 |
| Total Production from Continuing Operations | 19,840 | 18,098 | 21,170 |
| Canada — Discontinued Operations | 6,426 | 7,673 | 8,009 |
| Total Production | 26,266 | 25,771 | 29,179 |
| **Oil Production** *(Mbbl)* | | | |
| Gulf Coast | 717 | 685 | 989 |
| West Coast | 2,403 | 2,582 | 2,544 |
| Appalachia | 124 | 69 | 36 |
| Total Production from Continuing Operations | 3,244 | 3,336 | 3,569 |
| Canada — Discontinued Operations | 206 | 272 | 300 |
| Total Production | 3,450 | 3,608 | 3,869 |

**Average Prices**

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Average Gas Price/Mcf** | | | |
| Gulf Coast | $ 6.58 | $ 8.01 | $ 7.05 |
| West Coast | $ 6.54 | $ 7.93 | $ 6.85 |
| Appalachia | $ 7.48 | $ 9.53 | $ 7.60 |
| Weighted Average for Continuing Operations | $ 6.82 | $ 8.42 | $ 7.13 |
| Weighted Average After Hedging for Continuing Operations(1) | $ 7.25 | $ 7.02 | $ 6.26 |
| Canada — Discontinued Operations | $ 6.09 | $ 7.14 | $ 6.15 |
| **Average Oil Price/Barrel (bbl)** | | | |
| Gulf Coast | $63.04 | $64.10 | $49.78 |
| West Coast(2) | $56.86 | $56.80 | $42.91 |
| Appalachia | $62.26 | $65.28 | $48.28 |
| Weighted Average for Continuing Operations | $58.43 | $58.47 | $44.87 |
| Weighted Average After Hedging for Continuing Operations(1) | $51.68 | $40.26 | $26.59 |
| Canada — Discontinued Operations | $50.06 | $51.40 | $42.97 |

(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.

### 2007 Compared with 2006

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

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

### 2006 Compared with 2005

Operating revenues from continuing operations for the Exploration and Production segment increased $44.2 million in 2006 as compared with 2005. Oil production revenue after hedging increased $39.4 million due primarily to higher weighted average prices after hedging ($13.67 per barrel). This increase was offset slightly by a decrease in production (233,000 barrels). Gas production revenue after hedging decreased $5.6 million. A decrease in gas production (3,072 MMcf) more than offset an increase in the weighted average price of gas after hedging ($0.76 per Mcf). The decrease in gas production occurred primarily in the Gulf Coast (a 3,358 MMcf decline), which is partly attributable to the fall 2005 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.

### Earnings

### 2007 Compared with 2006

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

### 2006 Compared with 2005

The Exploration and Production segment's earnings from continuing operations in 2006 were $67.5 million, an increase of $31.9 million when compared with earnings from continuing operations of $35.6 million in 2005. The increase is primarily the result of higher oil and gas prices, which increased earnings by $29.6 million and $8.9 million, respectively. 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 ($2.2 million). 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. Partly offsetting these increases, lower gas and oil production decreased earnings by $12.5 million and $4.0 million, respectively. Further contributing to the decrease were higher general and administrative and other operating costs ($2.0 million) and higher lease operating expenses ($1.9 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 were 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.

## ENERGY MARKETING

### Revenues

### Energy Marketing Operating Revenues

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Natural Gas (after Hedging) | $413,405 | $496,769 | $329,560 |
| Other | 207 | 300 | 154 |
| | $413,612 | $497,069 | $329,714 |

### Energy Marketing Volumes

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| Natural Gas — (MMcf) | 50,775 | 45,270 | 40,683 |

### 2007 Compared with 2006

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

### 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.

### Earnings

### 2007 Compared with 2006

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

### 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.

## TIMBER

### Revenues

### Timber Operating Revenues

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Log Sales | $21,927 | $23,077 | $22,478 |
| Green Lumber Sales | 5,097 | 7,123 | 7,296 |
| Kiln-dried Lumber Sales | 27,908 | 32,809 | 29,651 |
| Other | 3,965 | 2,020 | 1,861 |
| | $58,897 | $65,029 | $61,286 |

### Timber Board Feet

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Log Sales | 8,660 | 9,527 | 7,601 |
| Green Lumber Sales | 9,358 | 10,454 | 10,489 |
| Kiln-dried Lumber Sales | 14,778 | 16,862 | 15,491 |
| | 32,796 | 36,843 | 33,581 |

### 2007 Compared with 2006

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

### 2006 Compared with 2005

Operating revenues for the Timber segment increased $3.7 million in 2006 as compared with 2005. This increase is attributed to an increase in kiln-dried lumber sales of $3.2 million primarily due to an increase in kiln-dried cherry lumber sales volumes of 2.0 million board feet. Other kiln-dried 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.

### Earnings

### 2007 Compared with 2006

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

### 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-dried lumber sales and cherry export log sales accounted for the earnings increase.

## 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 Income from Unconsolidated Subsidiaries on the Consolidated Statements of Income. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. ESNE generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. 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 assets. The former International segment activity primarily consists of project development activities in Italy and Bulgaria.

### Earnings

### 2007 Compared with 2006

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

### 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. 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. The Company 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. 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).

## INTEREST INCOME

Interest income was $7.9 million lower in 2007 as compared to 2006. As discussed in the Utility earnings section above, the main reason for this decrease was lower interest income of $7.4 million on a pension-related regulatory asset in accordance with the 2005 New York rate agreement. The New York division's 2005 rate agreement with the NYPSC allows the Company to accrue interest on a pension-related regulatory asset. The amount of the interest that can be accrued is reduced as the funded status of the pension plan improves. The fair market value of the pension plan assets exceeded the accumulated benefit obligation at September 30, 2007 resulting in a significant reduction in the interest accrual related to this regulatory asset in 2007.

Interest income was $3.2 million higher in 2006 as 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 regulatory asset in accordance with the New York rate agreement increased by $0.5 million.

## OTHER INCOME

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

Other income was $9.9 million lower in 2006 as 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.

## INTEREST CHARGES

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

Interest on long-term debt decreased $4.2 million in 2007 and $0.6 million in 2006. The decrease in 2007 was primarily the result of a lower average amount of long-term debt outstanding. In addition, the Company recognized a $1.9 million benefit to interest expense as a result of the discontinuance of hedge accounting for Empire's interest rate collar, as discussed above under Pipeline and Storage. The underlying long-term debt associated with this interest rate collar was repaid in December 2006 and the unrealized gain recorded in accumulated other comprehensive income associated with the interest rate collar was reclassified to interest expense during the quarter ended December 31, 2006.

Other interest charges were $0.1 million higher in 2007 and $3.1 million lower in 2006. The decrease in 2006 resulted primarily from the non-recurrence of $2.1 million of interest expense recorded by the Utility segment in 2005 and a lower average amount of short-term debt outstanding during 2006. The $2.1 million of interest expense recorded in 2005 related to an adjustment to a regulatory liability 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 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Millions) | |
| Provided by Operating Activities | $ 394.2 | $ 471.4 | $ 317.3 |
| Capital Expenditures | (276.7) | (294.2) | (219.5) |
| Investment in Partnership | (3.3) | — | — |
| Net Proceeds from Sale of Foreign Subsidiaries | 232.1 | — | 111.6 |
| Cash Held in Escrow | (58.2) | — | — |
| Net Proceeds from Sale of Oil and Gas Producing Properties | 5.1 | — | 1.4 |
| Other Investing Activities | (0.8) | (3.2) | 3.2 |
| Change in Short-Term Debt | — | — | (115.4) |
| Reduction of Long-Term Debt | (119.6) | (9.8) | (13.3) |
| Issuance of Common Stock | 17.5 | 23.3 | 20.3 |
| Dividends Paid on Common Stock | (100.6) | (98.2) | (94.1) |
| Dividends Paid to Minority Interest | — | — | (12.7) |
| Excess Tax Benefits Associated with Stock- Based Compensation Awards | 13.7 | 6.5 | — |
| Shares Repurchased under Repurchase Plan | (48.1) | (85.2) | — |
| Effect of Exchange Rates on Cash | (0.1) | 1.4 | 1.3 |
| Net Increase in Cash and Temporary Cash Investments | $ 55.2 | $ 12.0 | $ 0.1 |

## 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 and gain on sale of discontinued operations.

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

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil. The Company uses various derivative financial instruments, including price swap agreements, no cost collars and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $394.2 million in 2007, a decrease of $77.2 million compared with the $471.4 million provided by operating activities in 2006. Higher working capital requirements in the Exploration and Production, Utility, and Pipeline and Storage segments were partially offset by lower working capital requirements in the Energy Marketing segment.

## INVESTING CASH FLOW

### Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets associated with continuing operations totaled $250.9 million in 2007. The table below presents these expenditures:

| | Year Ended September 30, 2007 | | |
|---|---|---|---|
| | Capital Expenditures | Investment in Partnership | Total Expenditures For Long-Lived Assets |
| | | (Millions) | |
| Utility | $ 54.2 | $ — | $ 54.2 |
| Pipeline and Storage | 43.2 | — | 43.2 |
| Exploration and Production | 146.7 | — | 146.7 |
| Timber | 3.7 | — | 3.7 |
| All Other and Corporate | (0.2) | 3.3 | 3.1 |
| Total Expenditures from Continuing Operations(1) | $247.6 | $3.3 | $250.9 |

(1) Excludes expenditures for long-lived assets associated with discontinued operations of $29.1 million.

### 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. It also reflects $15.5 million of costs related to the Empire Connector project that were added to Construction Work in Progress during 2007. The Empire Connector project is discussed below under Estimated Capital Expenditures.

### Exploration and Production

The Exploration and Production segment's capital expenditures were primarily well drilling and completion expenditures and included approximately $66.2 million for the Gulf Coast region ($65.7 million for the off-shore program in the Gulf of Mexico), $41.4 million for the West Coast region and $39.1 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 $30.3 million spent to develop proved undeveloped reserves.

### Timber

The majority of the Timber segment capital expenditures were for the construction of two new kilns that were placed into service during the quarter ended June 30, 2007, as well as construction of a lumber sorter for Highland's sawmill operations, which was placed into service in October 2007.

### All Other and Corporate

The majority of the All Other and Corporate category expenditures for long-lived assets consisted of a $3.3 million capital contribution to Seneca Energy by Horizon Power, $1.65 million in each of the first and second quarters of fiscal 2007. Seneca Energy generates and sells electricity using methane gas obtained from landfills owned by outside parties. Seneca Energy is in the process of expanding its generating capacity from 11.2 megawatts to 17.6 megawatts. Horizon Power has funded its capital contributions with short-term borrowings.

### Estimated Capital Expenditures

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2008 | 2009 | 2010 |
| | | (Millions) | |
| Utility | $ 59.0 | $ 57.0 | $ 56.0 |
| Pipeline and Storage | 152.0 | 96.0 | 40.0 |
| Exploration and Production(1) | 154.0 | 146.0 | 143.0 |
| Timber | 1.0 | — | — |
| | $366.0 | $299.0 | $239.0 |

(1) Includes estimated expenditures for the years ended September 30, 2008, 2009 and 2010 of approximately $33 million, $36 million and $27 million, respectively, to develop proved undeveloped reserves.

Estimated capital expenditures for the Utility segment in 2008 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 2008 includes $122.9 million for the Empire Connector project as discussed below. Other capital expenditures will be concentrated in the replacement of transmission and storage lines, reconditioning of storage wells and improvements of compressor stations.

The Company continues to explore various opportunities to expand its capabilities to transport gas to the East Coast, either through the Supply Corporation or Empire systems or in partnership with others. 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 asked that Empire's existing business and facilities be brought under FERC jurisdiction, and that the FERC approve rates for Empire's existing and proposed services. The Empire Connector will provide an upstream supply link for the Millennium Pipeline, which began construction in June 2007, and will transport Canadian and other natural gas supplies to downstream customers. The Empire Connector is designed to move up to approximately 250 MDth of natural gas per day. On December 21, 2006, the FERC issued an order granting a Certificate of Public Convenience and Necessity authorizing the construction and operation of the Empire Connector and various other related pipeline projects by other unaffiliated companies, which has been accepted by Empire and the other applicants. In June 2007, Empire and KeySpan Gas East Corporation (KeySpan) executed a binding firm transportation service agreement for 150.75 MDth per day, obligating Empire to provide transportation service that will require construction of the Empire Connector project. Construction of the Empire Connector began in September 2007 and the planned in-service date is November 2008. 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 two years are as follows: $122.9 million in 2008 and $34.4 million in 2009. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The total cost to the Company of the Empire Connector project is estimated at $177 million, after giving effect to sales tax exemptions worth approximately $3.7 million. The Company anticipates financing this project with cash on hand and/or through the use of the Company's lines of credit. As of September 30, 2007, the Company had incurred approximately $19.7 million in costs related to this project. Of this amount, $13.7 million, $2.0 million and $3.4 million were incurred during the years ended September 30, 2007, 2006 and 2005, respectively. During the quarter ended June 30, 2007, the Company reversed the reserve established for these costs, as discussed above under Results of Operations, following the execution of the KeySpan service agreement. As of September 30, 2007, all of the costs incurred to date related to this project have been capitalized as either Construction Work in Progress ($15.5 million) or Materials and Supplies Inventory ($4.2 million), as per the accounting guidance in the FERC's Uniform System of Accounts and SFAS 71.

Supply Corporation continues to view its potential Tuscarora Extension project as an important link to Millennium and potential storage development in the Corning, New York area. This 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, could 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. Supply Corporation is also developing a project to meet the results of an "Open Season" seeking customers for new capacity from the Rockies Express Project, Appalachian production, storage and other points to Leidy and to interconnections with Millennium and Empire at Corning. This new project (the "West to East Project") could include the Tuscarora Extension, or could be a second phase following the development of that project. The timeline of both of these projects depends 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 lines of credit. The capital cost of the West to East project could amount to $700 million, which would be financed by a combination of debt and equity. There have been no costs incurred by the Company related to either project as of September 30, 2007, and the forecasted expenditures for the Tuscarora Extension Project over the next three years are as follows: $0 in 2008, $34.0 million in 2009, and $15.0 million in 2010. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The Company has not yet forecast any expenditures for the West to East Project. The Company has not yet filed an application with the FERC for the authority to build either project.

Estimated capital expenditures in 2008 for the Exploration and Production segment include approximately $50.0 million for the Gulf Coast region ($48.0 million on the off-shore program in the Gulf of Mexico), $46.0 million for the West Coast region and $58.0 million for the Appalachian region.

Estimated capital expenditures in 2008 in the Timber segment will be concentrated on the purchase of new equipment, vehicles and improvements to facilities for this segment's lumber yard, sawmill and kiln operations.

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

## FINANCING CASH FLOW

The Company did not have any outstanding short-term notes payable to banks or commercial paper at September 30, 2007. However, the Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $455.0 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, 2007, the Company's debt to capitalization ratio (as calculated under the facility) was .38. The constraints specified in the committed credit facility would permit an additional $2.02 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, 2007, the Company would have been permitted to issue up to a maximum of $1.4 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 40%) of the Company's long-term debt (as of September 30, 2007) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2007, 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, 2007 and September 30, 2006. 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 these securities if warranted by market conditions and the Company's capital requirements. Any offer and sale of these 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 April 30, 2007, the Company redeemed $96.3 million of 6.5% unsecured notes, plus accrued interest. These notes were redeemable by the Company at par at any time after September 15, 2006. On December 8, 2006, the Company repaid $22.8 million of Empire's secured debt. Such amount was classified as Current Portion of Long-Term Debt on the Company's Consolidated Balance Sheet at September 30, 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. As of September 30, 2007, the Company has repurchased 3,834,878 shares for $133.2 million under this program, including 1,308,328 shares for $48.1 million during fiscal 2007. These share repurchases were funded with cash provided by operating activities and/or through the use of the Company's lines of credit. 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 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 $35.5 million. These leases have been entered into for the use of buildings, vehicles, construction tools, meters and other items and are accounted for as operating leases. The Company's unconsolidated subsidiaries, which are accounted for under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $4.8 million. The Company has guaranteed 50%, or $2.4 million, of these capital lease commitments.

## CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2007, and the twelve-month periods over which they occur:

| | Payments by Expected Maturity Dates | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Thereafter | Total |
| | | | | (Millions) | | | |
| Long-Term Debt, including interest expense(1) | $259.8 | $148.4 | $45.5 | $232.7 | $171.8 | $439.3 | $1,297.5 |
| Operating Lease Obligations | $ 6.7 | $ 5.8 | $ 4.4 | $ 2.9 | $ 2.6 | $ 13.1 | $ 35.5 |
| Capital Lease Obligations | $ 0.9 | $ 0.5 | $ 0.4 | $ 0.4 | $ 0.2 | $ — | $ 2.4 |
| Purchase Obligations: | | | | | | | |
| Gas Purchase Contracts(2) | $718.1 | $ 67.2 | $ 7.1 | $ 2.8 | $ 2.8 | $ 16.2 | $ 814.2 |
| Transportation and Storage Contracts | $ 48.4 | $ 47.3 | $43.7 | $ 19.3 | $ 6.0 | $ 7.1 | $ 171.8 |
| Empire Connector Project Obligations(3) | $118.3 | $ 0.6 | $ — | $ — | $ — | $ — | $ 118.9 |
| Other | $ 20.5 | $ 9.6 | $ 6.0 | $ 4.2 | $ 3.7 | $ 14.2 | $ 58.2 |

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

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

(3) The Empire Connector is scheduled to be placed in service by November 2008, at an estimated cost of $177 million. The Company has only committed itself to $118.9 million for the project at September 30, 2007.

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the consolidated balance sheet in accordance with SFAS 133 (see Item 7, MD&A under the heading "Critical Accounting Estimates — Accounting for Derivative Financial Instruments"); (ii) NFR obligations to purchase gas or to purchase gas transportation/storage services where the amounts due on those obligations each month are included on the consolidated balance sheet as a current liability; and (iii) other obligations which are reflected on the consolidated balance sheet. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

## OTHER MATTERS

In addition to the 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 73% of the Company's employees. The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it will continue making contributions to the Retirement Plan. During 2007, the Company contributed $24.9 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2008 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 a majority of its 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 2007, the Company contributed $42.3 million to the Post-Retirement Plan. The Company anticipates that the annual contribution to the Post-Retirement Plan in 2008 will be in the range of $25.0 million to $35.0 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 which existed at September 30, 2006, was fully utilized in 2007 in connection with the gain recognized on the sale of SECI.

## MARKET RISK SENSITIVE INSTRUMENTS

### Energy Commodity Price Risk

The Company, in its Exploration and Production segment, Energy Marketing segment, Pipeline and Storage segment, and All Other category, uses various derivative financial instruments (derivatives), including price swap agreements, no cost collars and futures contracts, as part of the Company's overall energy commodity price risk management strategy. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from or pay to the respective counterparties at September 30, 2007 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial instruments.

The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2007. At September 30, 2007, 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 | | |
|---|---|---|---|
| | 2008 | 2009 | Total |
| Notional Quantities (Equivalent Bcf) | 12.2 | 1.0 | 13.2 |
| Weighted Average Fixed Rate (per Mcf) | $8.15 | $8.82 | $8.20 |
| Weighted Average Variable Rate (per Mcf) | $7.77 | $9.08 | $7.86 |

### *Crude Oil Price Swap Agreements*

| | Expected Maturity Dates | | |
|---|---|---|---|
| | 2008 | 2009 | Total |
| Notional Quantities (Equivalent bbls) | 1,305,000 | 180,000 | 1,485,000 |
| Weighted Average Fixed Rate (per bbl) | $ 57.72 | $ 54.70 | $ 57.35 |
| Weighted Average Variable Rate (per bbl) | $ 78.69 | $ 74.31 | $ 78.16 |

At September 30, 2007, the Company would have received from its respective counterparties an aggregate of approximately $2.8 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have had to pay an aggregate of approximately $11.2 million to its counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2007.

At September 30, 2006, the Company had natural gas price swap agreements covering 7.4 Bcf at a weighted average fixed rate of $7.24 per Mcf. The Company also had crude oil price swap agreements covering 900,000 bbls at a weighted average fixed rate of $37.13 per bbl. The increase in natural gas price swap agreements from September 2006 to September 2007 is largely attributable to management's decision to utilize fewer collars and more swaps. This decision was as a result of market conditions being less conducive to using collars than they were in the prior year. The increase in crude oil price swap agreements is primarily due to an increased availability of counterparties willing to enter into new swap agreements with terms that match the delivery points of its West Coast crude oil production.

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, 2007, the Company had not entered into any natural gas or crude oil no cost collars extending beyond 2008.

### *No Cost Collars*

| | Expected Maturity Date |
|---|---|
| | 2008 |
| **Natural Gas** | |
| Notional Quantities (Equivalent Bcf) | 1.4 |
| Weighted Average Ceiling Price (per Mcf) | $16.45 |
| Weighted Average Floor Price (per Mcf) | $ 8.83 |

At September 30, 2007, the Company would have received an aggregate of approximately $1.9 million to terminate the natural gas no cost collars outstanding at that date.

At September 30, 2006, the Company had natural gas no cost collars covering 7.1 Bcf at a weighted average floor price of $8.26 per Mcf and a weighted average ceiling price of $17.25 per Mcf. The Company also had crude oil no cost collars covering 180,000 bbls at 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 decrease in natural gas collars from September 2006 to September 2007 is due to management's decision to utilize fewer collars and more swaps. This is due to the market conditions discussed in the Swap Agreements section.

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, 2007, the Company held no futures contracts with maturity dates extending beyond 2012.

***Futures Contracts***

| | Expected Maturity Dates | | | | | |
|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Total |
| Net Contract Volumes Purchased (Sold) (Equivalent Bcf) | 2.9 | (0.1) | — | —[1] | —[1] | 2.8 |
| Weighted Average Contract Price (per Mcf) | $9.08 | $9.50 | NA | $6.99 | $8.68 | $9.11 |
| Weighted Average Settlement Price (per Mcf) | $8.94 | $9.13 | NA | $6.31 | $9.00 | $8.96 |

(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, 2007, the Company would have received $2.2 million to terminate these futures contracts.

At September 30, 2006, the Company had futures contracts covering 7.0 Bcf (net long position) at a weighted average contract price of $9.67 per Mcf.

The decrease in net long positions at September 30, 2007 as compared to September 30, 2006 is attributed to fewer customers entering into fixed price sales commitments at September 30, 2007 as compared to September 30, 2006. Management believes this is due to the lack of a significant decrease in natural gas prices at the end of 2007 as compared to 2006, sufficient natural gas in storage throughout the United States, and forecasts for a mild winter. As a result, the Energy Marketing segment had purchased fewer futures contracts as of September 30, 2007 as compared to September 30, 2006 to hedge against a lower number of fixed price sales commitments.

The Company may be exposed to credit risk on some of the derivatives disclosed above. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check and then, on an ongoing basis, monitors counterparty credit exposure. Management has obtained guarantees from many of the parent companies of the respective counterparties to its derivatives. At September 30, 2007, the Company used nine counterparties for its over-the-counter derivatives. At September 30, 2007, no individual counterparty represented greater than 32% 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, 2007.

## Exchange Rate Risk

The Exploration and Production segment's investment in Canada was valued in Canadian dollars, and, as such, this investment was 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 resulted in increases or decreases to the CTA, a component of Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheets. When the foreign currency increased in value in relation to the U.S. dollar, there was a positive adjustment to CTA. When the foreign currency decreased in value in relation to the U.S. dollar, there was a negative adjustment to CTA. In August 2007, the Exploration and Production segment's investment in Canada was sold, eliminating the Company's major foreign operations. Of the $232.1 million in net proceeds received, $58.0 million was placed in escrow (denominated in Canadian dollars) pending receipt of a tax clearance certificate from the Canadian government. To hedge against foreign currency exchange risk, the Company entered into a $58.0 million forward contract to sell Canadian dollars. At September 30, 2007, due to the increase in the strength of the Canadian dollar versus the U.S. dollar, the Company had a $2.7 million derivative liability related to the collar. The Company records gains or losses associated with this forward contract directly to the income statement.

### Interest Rate Risk

On December 8, 2006, the Company repaid $22.8 million of Empire's secured debt. The interest costs of this secured debt were hedged by an interest rate collar. Since the hedged transaction was settled and there will be no future cash flows associated with the secured debt, hedge accounting for the interest rate collar was discontinued and the unrealized gain in accumulated other comprehensive income associated with the interest rate collar was reclassified to the Consolidated Statement of Income.

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, 2007:

| | Principal Amounts by Expected Maturity Dates | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Thereafter | Total |
| | (Dollars in millions) | | | | | | |
| Long-Term Fixed Rate Debt . . . . . . . | $200.0(1) | $100.0 | $— | $200.0 | $150.0 | $349.0 | $999.0 |
| Weighted Average Interest Rate Paid . . . . . . . . . . . . . . . . . . . . . . . | 6.3% | 6.0% | — | 7.5% | 6.7% | 5.9% | 6.4% |
| Fair Value = $1,024.4 | | | | | | | |

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

## RATE AND REGULATORY MATTERS

### Utility Operation

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

### New York Jurisdiction

On 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 rate agreement, substantially as filed, for an effective date of August 1, 2005. The rate agreement provided 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 until new rates should go into effect, the return on equity level above which earnings must be shared with rate payers is 11.5%.

On January 29, 2007, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by $52.0 million. Following standard procedure, the NYPSC suspended the proposed tariff amendments to enable its staff and intervenors to conduct a routine investigation and hold hearings. Distribution Corporation explained in the filing that its request for rate relief is necessitated by decreased revenues resulting from customer conservation efforts and increased customer uncollectibles, among other things. The rate filing also includes a proposal for an aggressive efficiency and conservation initiative with a revenue decoupling mechanism designed to render the Company indifferent to throughput reductions resulting from conservation. On September 20, 2007, the NYPSC issued an order approving, with modifications, the Company's conservation program for implementation on an accelerated basis. Associated ratemaking issues, however, were reserved for consideration in the rate case. On September 28, 2007, an administrative law judge assigned to the proceeding issued a recommended decision (RD) based on a review and analysis of the evidence presented in the case. The RD recommends a rate increase designed to provide additional annual revenues of $2.5 million, together with a bill surcharge that would collect up to $10.8 million to recover expenses arising from the conservation program. The recommended cost of equity, subject to updates, is 9.4%. The RD also recommends approval of the unopposed revenue decoupling mechanism. The NYPSC is not bound to accept the RD, and may accept, reject or modify the Company's filing. Assuming standard procedure, rates would become effective in late December 2007. The outcome of the proceeding cannot be ascertained at this time.

### Pennsylvania Jurisdiction

On June 1, 2006, Distribution Corporation filed proposed tariff amendments with PaPUC to increase annual revenues by $25.9 million to cover increases in the cost of service to be effective July 30, 2006. The rate request was filed to address increased costs associated with Distribution Corporation's ongoing construction program as well as increases in operating costs, particularly uncollectible accounts. Following standard regulatory procedure, the PaPUC issued an order on July 20, 2006 instituting a rate proceeding and suspending the proposed tariff amendments until March 2, 2007. On October 2, 2006, the parties, including Distribution Corporation, Staff of the PaPUC and intervenors, executed an agreement (Settlement) proposing to settle all issues in the rate proceeding. The Settlement includes an increase in annual revenues of $14.3 million to non-gas revenues, an agreement not to file a rate case until January 28, 2008 at the earliest and an early implementation date. The Settlement was approved by the PaPUC at its meeting on November 30, 2006, and the new rates became effective January 1, 2007.

On June 8, 2006, the NTSB issued safety recommendations to Distribution Corporation, the PaPUC and certain other parties 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. Without admitting liability, Distribution Corporation settled all significant third-party claims against it related to the explosion.

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 implemented those recommendations. In December 2006, the NTSB classified its recommendations as "closed" after determining that Distribution Corporation took acceptable action with respect to the recommendations.

The NTSB's 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 has worked cooperatively with the Staff of the PaPUC to permit the PaPUC to undertake the analysis recommended by the NTSB.

In late November 2007, Distribution Corporation reached a Settlement Agreement with the Law Bureau Prosecutory Staff of the PaPUC (the "Law Bureau") regarding the explosion and the PaPUC's subsequent investigation. The Law Bureau and Distribution Corporation will jointly submit this Settlement Agreement to the PaPUC for approval. In the Settlement Agreement, Distribution Corporation agrees, without admitting liability, to pay a $50,000 fine and to fund an additional $30,000 of safety-related activities. Distribution Corporation also agrees to make various improvements to its butt-fusion procedures and to implement a program to review existing butt-fusions.

### Pipeline and Storage

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

Empire currently does not have a rate case on file with the NYPSC. Among the issues resolved in connection with Empire's FERC application to build the Empire Connector are the rates and terms of service that will become applicable to all of Empire's business, effective upon Empire constructing and placing its new facilities into service (currently expected for November 2008). At that time, Empire will become an interstate pipeline subject to FERC regulation. The order described in the following paragraph requires Empire to make a filing at FERC within three years after the in-service date justifying Empire's existing recourse rates or proposing alternative rates.

The FERC issued on December 21, 2006 an order granting a Certificate of Public Convenience and Necessity authorizing the construction and operation of the Empire Connector and various other related pipeline projects by other unaffiliated companies. The Empire Certificate contains various environmental and other conditions. Empire has accepted that Certificate. Additional environmental permits from the U.S. Army Corps of Engineers and state environmental agencies have been received. Empire has also received, from all six upstate New York counties in which it would build the Empire Connector project, final approval of sales tax exemptions and temporary partial property tax abatements necessary to enable the Empire Connector to generate a fair return. In June 2007, Empire signed a firm transportation service agreement with KeySpan Gas East Corporation, under which Empire is obligated to provide transportation service that will require construction of this project. Construction began in September 2007 and is planned to be complete by November 1, 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 Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2007, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $12.1 million to $15.8 million. The minimum estimated liability of $12.1 million has been recorded on the Consolidated Balance Sheet at September 30, 2007. 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 June 2006, the FASB issued FIN 48. FIN 48 clarifies the accounting for income taxes by prescribing a minimum probability threshold that a tax position must meet before a financial statement benefit is recognized. The minimum threshold is defined in FIN 48 as a tax position that is more likely than not to be sustained upon examination by the applicable taxing authority, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If a tax benefit meets this threshold, it is measured and recognized based on an analysis of the cumulative probability of the tax benefit being ultimately sustained. The cumulative effect of applying FIN 48 at adoption, if any, is reported as an adjustment to opening retained earnings for the year of adoption. FIN 48 is effective for the first quarter of the Company's 2008 fiscal year and it is expected that this pronouncement will not have a material effect on the Company's consolidated financial statements.

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. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. The pronouncement will be 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 issued SFAS 158, an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R. SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan's assets and obligations that determine its funded status be measured as of the end of Company's fiscal year, with limited exceptions. Under SFAS 158, certain previously unrecognized actuarial gains and losses and previously unrecognized prior service costs for both the pension and other post-retirement benefit plans as well as a previously unrecognized transition obligation for the other post-retirement benefit plan are required to be recognized. These amounts were not required to be recorded on the Company's Consolidated Balance Sheet before the adoption of SFAS 158, but were instead amortized over a period of time. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company's fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date. At September 30, 2007, in order to recognize the funded status of its pension and post-retirement benefit plans in accordance with SFAS 158, the Company recorded additional liabilities or reduced assets by a cumulative amount of $78.7 million ($71.1 million net of deferred tax benefits recognized for the portion recorded as an increase to Accumulated Other Comprehensive Loss). Of the $71.1 million recognized, $61.9 million was recorded as an increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments, $12.5 million (net of deferred tax benefits of $7.6 million) was recorded as an increase to Accumulated Other Comprehensive Loss, and $3.3 million was recorded as an increase to Other Regulatory Liabilities in the Company's Utility segment. The Company has recorded amounts to Other Regulatory Assets or Other Regulatory Liabilities in the Utility and Pipeline and Storage segments in accordance with the provisions of SFAS 71. The Company, in those segments, has certain regulatory commission authorizations, which allow the Company to defer as a regulatory asset or liability the difference between pension and post-retirement benefit costs as calculated in accordance with SFAS 87 and SFAS 106 and what is collected in rates. Refer to Item 8 at Note G — Retirement Plan and Other Post-Retirement Benefits for further disclosures regarding the impact of SFAS 158 on the Company's consolidated financial statements.

In February 2007, the FASB issued SFAS 159. SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not otherwise required to be measured at fair value under GAAP. A company that elects the fair value option for an eligible item will be required to recognize in current earnings any changes in that item's fair value in reporting periods subsequent to the date of adoption. SFAS 159 will be effective as of the Company's first quarter of fiscal 2009. The Company is currently evaluating the impact, if any, that the adoption of SFAS 159 will have on its consolidated financial statements.

## EFFECTS OF INFLATION

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

## SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, performance and capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words "anticipates," "estimates," "expects," "forecasts," "intends," "plans," "predicts," "projects," "believes," "seeks," "will" and "may" and similar expressions, are "forward-looking" statements as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Changes in economic conditions, including economic disruptions caused by terrorist activities, acts of war or major accidents;
2. Changes in demographic patterns and weather conditions, including the occurrence of severe weather such as hurricanes;
3. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment of derivative financial instruments or the valuation of the Company's natural gas and oil reserves;
4. Uncertainty of oil and gas reserve estimates;
5. Ability to successfully identify, drill for and produce economically viable natural gas and oil reserves;
6. Significant changes from expectations in the Company's actual production levels for natural gas or oil;
7. Changes in the availability and/or price of derivative financial instruments;
8. Changes in the price differentials between various types of oil;
9. Inability to obtain new customers or retain existing ones;
10. Significant changes in competitive factors affecting the Company;
11. Changes in laws and regulations to which the Company is subject, including changes in tax, environmental, safety and employment laws and regulations;
12. 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;
13. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;
14. Significant changes from expectations in actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs or plans;
15. The nature and projected profitability of pending and potential projects and other investments, and the ability to obtain necessary governmental approvals and permits;
16. Occurrences affecting the Company's ability to obtain funds from operations, from borrowings under our credit lines or other credit facilities or from issuances of other short-term notes or debt or equity securities to finance needed capital expenditures and other investments, including any downgrades in the Company's credit ratings;
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. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
19. Significant changes in tax rates or policies or in rates of inflation or interest;
20. 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;
21. Changes in accounting principles or the application of such principles to the Company;
22. The cost and effects of legal and administrative claims against the Company;
23. Changes in actuarial assumptions and the return on assets with respect to the Company's retirement plan and post-retirement benefit plans;
24. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide post-retirement benefits; or
25. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

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

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

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

***Index to Financial Statements***



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

***Supplementary Data***

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

## REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2007 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in "Management's Report on Internal Control Over Financial Reporting" appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

PricewaterhouseCoopers LLP

Buffalo, New York
November 29, 2007

## NATIONAL FUEL GAS COMPANY

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (Thousands of dollars, except per common share amounts) | | |
| **INCOME** | | | |
| **Operating Revenues** | $ 2,039,566 | $ 2,239,675 | $ 1,860,774 |
| **Operating Expenses** | | | |
| Purchased Gas | 1,018,081 | 1,267,562 | 959,827 |
| Operation and Maintenance | 396,408 | 395,289 | 388,094 |
| Property, Franchise and Other Taxes | 70,660 | 69,202 | 68,164 |
| Depreciation, Depletion and Amortization | 157,919 | 151,999 | 156,502 |
| | 1,643,068 | 1,884,052 | 1,572,587 |
| **Operating Income** | 396,498 | 355,623 | 288,187 |
| **Other Income (Expense):** | | | |
| Income from Unconsolidated Subsidiaries | 4,979 | 3,583 | 3,362 |
| Impairment of Investment in Partnership | — | — | (4,158) |
| Other Income | 4,936 | 2,825 | 12,744 |
| Interest Income | 1,550 | 9,409 | 6,236 |
| Interest Expense on Long-Term Debt | (68,446) | (72,629) | (73,244) |
| Other Interest Expense | (6,029) | (5,952) | (9,069) |
| **Income from Continuing Operations Before Income Taxes** | 333,488 | 292,859 | 224,058 |
| Income Tax Expense | 131,813 | 108,245 | 85,621 |
| **Income from Continuing Operations** | 201,675 | 184,614 | 138,437 |
| **Discontinued Operations:** | | | |
| Income (Loss) from Operations, Net of Tax | 15,479 | (46,523) | 25,277 |
| Gain on Disposal, Net of Tax | 120,301 | — | 25,774 |
| **Income (Loss) from Discontinued Operations, Net of Tax** | 135,780 | (46,523) | 51,051 |
| **Net Income Available for Common Stock** | 337,455 | 138,091 | 189,488 |
| **EARNINGS REINVESTED IN THE BUSINESS** | | | |
| Balance at Beginning of Year | 786,013 | 813,020 | 718,926 |
| | 1,123,468 | 951,111 | 908,414 |
| Share Repurchases | 38,196 | 66,269 | — |
| Dividends on Common Stock | 101,496 | 98,829 | 95,394 |
| **Balance at End of Year** | $ 983,776 | $ 786,013 | $ 813,020 |
| **Earnings Per Common Share:** | | | |
| Basic: | | | |
| Income from Continuing Operations | $ 2.43 | $ 2.20 | $ 1.66 |
| Income (Loss) from Discontinued Operations | 1.63 | (0.56) | 0.61 |
| **Net Income Available for Common Stock** | $ 4.06 | $ 1.64 | $ 2.27 |
| Diluted: | | | |
| Income from Continuing Operations | $ 2.37 | $ 2.15 | $ 1.63 |
| Income (Loss) from Discontinued Operations | 1.59 | (0.54) | 0.60 |
| **Net Income Available for Common Stock** | $ 3.96 | $ 1.61 | $ 2.23 |
| **Weighted Average Common Shares Outstanding:** | | | |
| Used in Basic Calculation | 83,141,640 | 84,030,118 | 83,541,627 |
| Used in Diluted Calculation | 85,301,361 | 86,028,466 | 85,029,131 |

See Notes to Consolidated Financial Statements

## NATIONAL FUEL GAS COMPANY

## CONSOLIDATED BALANCE SHEETS

| | At September 30 2007 | At September 30 2006 |
|---|---|---|
| | (Thousands of dollars) | |
| **ASSETS** | | |
| **Property, Plant and Equipment** | $4,461,586 | $4,703,040 |
| Less — Accumulated Depreciation, Depletion and Amortization | 1,583,181 | 1,825,314 |
| | 2,878,405 | 2,877,726 |
| **Current Assets** | | |
| Cash and Temporary Cash Investments | 124,806 | 69,611 |
| Cash Held in Escrow | 61,964 | — |
| Hedging Collateral Deposits | 4,066 | 19,676 |
| Receivables — Net of Allowance for Uncollectible Accounts of $28,654 and $31,427, Respectively | 172,380 | 173,671 |
| Unbilled Utility Revenue | 20,682 | 25,538 |
| Gas Stored Underground | 66,195 | 59,461 |
| Materials and Supplies — at average cost | 35,669 | 36,693 |
| Unrecovered Purchased Gas Costs | 14,769 | 12,970 |
| Other Current Assets | 45,057 | 63,723 |
| Deferred Income Taxes | 8,550 | 23,402 |
| | 554,138 | 484,745 |
| **Other Assets** | | |
| Recoverable Future Taxes | 83,954 | 79,511 |
| Unamortized Debt Expense | 12,070 | 15,492 |
| Other Regulatory Assets | 137,577 | 76,917 |
| Deferred Charges | 5,545 | 3,558 |
| Other Investments | 85,902 | 88,414 |
| Investments in Unconsolidated Subsidiaries | 18,256 | 11,590 |
| Goodwill | 5,476 | 5,476 |
| Intangible Assets | 28,836 | 31,498 |
| Prepaid Pension and Post-Retirement Benefit Costs | 61,006 | 64,125 |
| Fair Value of Derivative Financial Instruments | 9,188 | 11,305 |
| Deferred Income Taxes | — | 9,003 |
| Other | 8,059 | 4,388 |
| | 455,869 | 401,277 |
| **Total Assets** | $3,888,412 | $3,763,748 |
| **CAPITALIZATION AND LIABILITIES** | | |
| **Capitalization:** | | |
| **Comprehensive Shareholders' Equity** | | |
| Common Stock, $1 Par Value | | |
| Authorized — 200,000,000 Shares; Issued and Outstanding — 83,461,308 Shares and 83,402,670 Shares, Respectively | $ 83,461 | $ 83,403 |
| Paid In Capital | 569,085 | 543,730 |
| Earnings Reinvested in the Business | 983,776 | 786,013 |
| Total Common Shareholders' Equity Before Items Of Other Comprehensive Income (Loss) | 1,636,322 | 1,413,146 |
| Accumulated Other Comprehensive Income (Loss) | (6,203) | 30,416 |
| **Total Comprehensive Shareholders' Equity** | 1,630,119 | 1,443,562 |
| **Long-Term Debt, Net of Current Portion** | 799,000 | 1,095,675 |
| **Total Capitalization** | 2,429,119 | 2,539,237 |
| **Current and Accrued Liabilities** | | |
| Notes Payable to Banks and Commercial Paper | — | — |
| Current Portion of Long-Term Debt | 200,024 | 22,925 |
| Accounts Payable | 109,757 | 133,034 |
| Amounts Payable to Customers | 10,409 | 23,935 |
| Dividends Payable | 25,873 | 25,008 |
| Interest Payable on Long-Term Debt | 18,158 | 18,420 |
| Customer Advances | 22,863 | 29,417 |
| Other Accruals and Current Liabilities | 36,062 | 27,040 |
| Fair Value of Derivative Financial Instruments | 16,200 | 39,983 |
| | 439,346 | 319,762 |
| **Deferred Credits** | | |
| Deferred Income Taxes | 575,356 | 544,502 |
| Taxes Refundable to Customers | 14,026 | 10,426 |
| Unamortized Investment Tax Credit | 5,392 | 6,094 |
| Cost of Removal Regulatory Liability | 91,226 | 85,076 |
| Other Regulatory Liabilities | 76,659 | 75,456 |
| Post-Retirement Liabilities | 70,555 | 32,918 |
| Asset Retirement Obligations | 75,939 | 77,392 |
| Other Deferred Credits | 110,794 | 72,885 |
| | 1,019,947 | 904,749 |
| **Commitments and Contingencies** | — | — |
| **Total Capitalization and Liabilities** | $3,888,412 | $3,763,748 |

See Notes to Consolidated Financial Statements

## NATIONAL FUEL GAS COMPANY

## CONSOLIDATED STATEMENTS OF CASH FLOWS

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (Thousands of dollars) | | |
| **Operating Activities** | | | |
| Net Income Available for Common Stock | $ 337,455 | $ 138,091 | $ 189,488 |
| Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities: | | | |
| Gain on Sale of Discontinued Operations | (159,873) | — | (27,386) |
| Impairment of Oil and Gas Producing Properties | — | 104,739 | — |
| Depreciation, Depletion and Amortization | 170,803 | 179,615 | 193,144 |
| Deferred Income Taxes | 52,847 | (5,230) | 40,388 |
| Income from Unconsolidated Subsidiaries, Net of Cash Distributions | (3,366) | 1,067 | (1,372) |
| Impairment of Investment in Partnership | — | — | 4,158 |
| Minority Interest in Foreign Subsidiaries | — | — | 2,645 |
| Excess Tax Benefits Associated with Stock-Based Compensation Awards | (13,689) | (6,515) | — |
| Other | 16,399 | 4,829 | 7,390 |
| Change in: | | | |
| Hedging Collateral Deposits | 15,610 | 58,108 | (69,172) |
| Receivables and Unbilled Utility Revenue | 5,669 | (12,343) | (25,828) |
| Gas Stored Underground and Materials and Supplies | (5,714) | 1,679 | 1,934 |
| Unrecovered Purchased Gas Costs | (1,799) | 1,847 | (7,285) |
| Prepayments and Other Current Assets | 18,800 | (39,572) | (42,409) |
| Accounts Payable | (26,002) | (23,144) | 48,089 |
| Amounts Payable to Customers | (13,526) | 22,777 | (1,996) |
| Customer Advances | (6,554) | 4,946 | 3,971 |
| Other Accruals and Current Liabilities | 8,950 | (17,754) | 18,715 |
| Other Assets | 4,109 | (22,700) | (13,461) |
| Other Liabilities | (5,922) | 80,960 | (3,667) |
| **Net Cash Provided by Operating Activities** | 394,197 | 471,400 | 317,346 |
| **Investing Activities** | | | |
| Capital Expenditures | (276,728) | (294,159) | (219,530) |
| Investment in Partnership | (3,300) | — | — |
| Net Proceeds from Sale of Foreign Subsidiaries | 232,092 | — | 111,619 |
| Cash Held in Escrow | (58,248) | — | — |
| Net Proceeds from Sale of Oil and Gas Producing Properties | 5,137 | 13 | 1,349 |
| Other | (725) | (3,230) | 3,238 |
| **Net Cash Used in Investing Activities** | (101,772) | (297,376) | (103,324) |
| **Financing Activities** | | | |
| Change in Notes Payable to Banks and Commercial Paper | — | — | (115,359) |
| Excess Tax Benefits Associated with Stock-Based Compensation Awards | 13,689 | 6,515 | — |
| Shares Repurchased under Repurchase Plan | (48,070) | (85,168) | — |
| Reduction of Long-Term Debt | (119,576) | (9,805) | (13,317) |
| Net Proceeds from Issuance of Common Stock | 17,498 | 23,339 | 20,279 |
| Dividends Paid on Common Stock | (100,632) | (98,266) | (94,159) |
| Dividends Paid to Minority Interest | — | — | (12,676) |
| **Net Cash Used in Financing Activities** | (237,091) | (163,385) | (215,232) |
| **Effect of Exchange Rates on Cash** | (139) | 1,365 | 1,276 |
| **Net Increase in Cash and Temporary Cash Investments** | 55,195 | 12,004 | 66 |
| **Cash and Temporary Cash Investments At Beginning of Year** | 69,611 | 57,607 | 57,541 |
| **Cash and Temporary Cash Investments At End of Year** | $ 124,806 | $ 69,611 | $ 57,607 |
| **Supplemental Disclosure of Cash Flow Information** | | | |
| **Cash Paid For:** | | | |
| Interest | $ 75,987 | $ 78,003 | $ 84,455 |
| Income Taxes | $ 97,961 | $ 54,359 | $ 83,542 |

See Notes to Consolidated Financial Statements

## NATIONAL FUEL GAS COMPANY

## CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (Thousands of dollars) | | |
| Net Income Available for Common Stock | $337,455 | $138,091 | $ 189,488 |
| Other Comprehensive Income (Loss), Before Tax: | | | |
| Minimum Pension Liability Adjustment | — | 165,914 | (83,379) |
| Foreign Currency Translation Adjustment | 7,874 | 7,408 | 14,286 |
| Reclassification Adjustment for Realized Foreign Currency Translation Gain in Net Income | (42,658) | (716) | (37,793) |
| Unrealized Gain on Securities Available for Sale Arising During the Period | 4,747 | 2,573 | 2,891 |
| 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 | 8,495 | 90,196 | (206,847) |
| Reclassification Adjustment for Realized Loss on Derivative Financial Instruments in Net Income | 5,106 | 91,743 | 97,689 |
| Other Comprehensive Income (Loss), Before Tax | (16,436) | 357,118 | (213,804) |
| Income Tax Expense (Benefit) Related to Minimum Pension Liability Adjustment | — | 58,070 | (29,183) |
| 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 | 1,724 | 894 | 1,012 |
| 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 | 3,153 | 34,772 | (79,059) |
| Reclassification Adjustment for Income Tax Benefit on Realized Loss on Derivative Financial Instruments In Net Income | 2,824 | 35,338 | 36,507 |
| Income Taxes — Net | 7,701 | 129,074 | (70,951) |
| Other Comprehensive Income (Loss) | (24,137) | 228,044 | (142,853) |
| Comprehensive Income | $313,318 | $366,135 | $ 46,635 |

See Notes to Consolidated Financial Statements

## Note A — Summary of Significant Accounting Policies

### *Principles of Consolidation*

The Company consolidates its majority owned entities. The equity method is used to account for minority owned entities. All significant intercompany balances and transactions are eliminated. The Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

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

### *Reclassification*

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

### *Regulation*

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

### *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 Energy Marketing segment records revenue as bills are rendered for service supplied on a calendar month basis.

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

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

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

### *Allowance for Uncollectible Accounts*

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

***Regulatory Mechanisms***

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

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

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a WNC, which covers the eight-month period from October through May. The WNC is designed to adjust the rates of retail customers to reflect the impact of deviations from normal weather. Weather that is 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.

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

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

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on a country-by-country basis on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying current market prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2007, 2006, and 2005, estimated future net cash flows were increased by $2.2 million, increased by $4.7 million, and decreased by $175.3 million, respectively. The Company's capitalized costs exceeded the full cost ceiling for the Company's Canadian properties at June 30, 2006 and September 30, 2006. As such, the Company recognized pre-tax impairments of $62.4 million at June 30, 2006 and $42.3 million at September 30, 2006. These impairment charges are included in loss from discontinued operations for 2006 due to the sale of SECI during 2007.

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

### *Depreciation, Depletion and Amortization*

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

| | As of September 30 | |
|---|---|---|
| | 2007 | 2006 |
| | (Thousands) | |
| Utility | $1,539,808 | $1,493,991 |
| Pipeline and Storage | 976,316 | 962,831 |
| Exploration and Production(1) | 1,577,745 | 1,899,777 |
| Energy Marketing | 1,199 | 1,123 |
| Timber | 119,237 | 116,281 |
| All Other and Corporate | 32,806 | 33,338 |
| | $4,247,111 | $4,507,341 |

(1) Fiscal 2006 includes the depreciable plant of SECI discontinued operations of $469,810.

Average depreciation, depletion and amortization rates are as follows:

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| Utility | 2.8% | 2.8% | 2.8% |
| Pipeline and Storage | 3.5% | 4.0% | 4.1% |
| Exploration and Production, per Mcfe(1) | $1.94 | $2.00 | $1.74 |
| Energy Marketing | 2.8% | 4.8% | 7.6% |
| Timber | 4.0% | 5.6% | 6.2% |
| All Other and Corporate | 4.6% | 4.1% | 4.3% |

(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 $1.92, $1.98 and $1.72 per Mcfe of production in 2007, 2006 and 2005, respectively. Depletion of oil and gas producing properties in the United States amounted to $1.97, $1.74 and $1.58 per Mcfe of production in 2007, 2006 and 2005, respectively. Depletion of oil and gas producing properties in Canada amounted to $1.67, $2.95 and $2.36 per Mcfe of production in 2007, 2006 and 2005, respectively.

### *Goodwill*

The Company has recognized goodwill of $5.5 million as of September 30, 2007 and 2006 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, 2007 and 2006, the fair value of Empire was greater than its book value. As such, the goodwill was considered not impaired.

### *Financial Instruments*

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

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments include price swap agreements, no cost collars and futures contracts. The Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled fair value of derivative financial instruments. Fair value represents the amount the Company would receive or pay to terminate these instruments.

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

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 2007, 2006 or 2005.

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

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

| | Year Ended September 30 | |
|---|---|---|
| | 2007 | 2006 |
| | (Thousands) | |
| Funded Position of the Pension and Other Post-Retirement Benefit Plans Adjustment | $(12,482)(1) | $ — |
| Cumulative Foreign Currency Translation Adjustment | (83) | 34,701 |
| Net Unrealized Loss on Derivative Financial Instruments | (3,886) | (11,510) |
| Net Unrealized Gain on Securities Available for Sale | 10,248 | 7,225 |
| Accumulated Other Comprehensive Income (Loss) | $ (6,203) | $ 30,416 |

(1) In accordance with the transition recognition provisions of SFAS 158, the adjustment to recognize the funded positions of the Pension and Other Post-retirement Benefit Plans are shown as an adjustment to the ending balance of accumulated other comprehensive income (loss). The adjustment is not shown as other comprehensive income (loss) in the Consolidated Statements of Comprehensive Income.

At September 30, 2007, it is estimated that of the $3.9 million net unrealized loss on derivative financial instruments shown in the table above, $2.4 million will be reclassified into the Consolidated Statement of Income during 2008. The remaining unrealized loss on derivative financial instruments of $1.5 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.

### *Gas Stored Underground — Current*

In the Utility segment, gas stored underground — current in the amount of $33.0 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 2007, 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 $129.3 million at September 30, 2007. 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 | |
|---|---|---|
| | 2007 | 2006 |
| | (Thousands) | |
| Materials and Supplies | $ 8,925 | $13,174 |
| Other Assets | 5,641 | 3,218 |
| | $14,566 | $16,392 |

### *Unamortized Debt Expense*

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

### *Foreign Currency Translation*

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

### *Income Taxes*

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

### *Consolidated Statements of Cash Flows*

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

### *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.

***Cash Held in Escrow***

On August 31, 2007, the Company received approximately $232.1 million of proceeds from the sale of SECI, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. The escrow account is a Canadian dollar denominated account. On a U.S. dollar basis, the value of this account was $62.0 million at September 30, 2007.

***Other Current Assets***

Other Current Assets consist of prepayments in the amounts of $14.1 million and $12.0 million at September 30, 2007 and 2006, respectively, prepaid property and other taxes of $14.1 million and $13.7 million at September 30, 2007 and 2006, respectively, federal income taxes receivable in the amounts of $8.7 million and $7.5 million at September 30, 2007 and 2006, respectively, state income taxes receivable in the amounts of zero and $7.4 million at September 30, 2007 and 2006, respectively, and fair values of firm commitments in the amounts of $8.2 million and $23.1 million at September 30, 2007 and 2006, 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 and stock-settled SARs. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these stock options and stock-settled SARs as determined using the Treasury Stock Method. Stock options and stock-settled SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2007, no stock options or stock-settled SARs were excluded as being antidilutive. For 2006, 119,241 stock options were excluded as being antidilutive. There were no stock-settled SARs excluded as being antidilutive for 2006. There were no stock options or stock-settled SARs excluded as being antidilutive for 2005.

***Share Repurchases***

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

***Stock-Based Compensation***

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, stock-settled SARs, restricted stock, performance units or performance shares. Stock options and stock-settled SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no stock option or stock-settled SAR is exercisable less than one year or more than ten years after the date of each grant. Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. Certificates for shares of restricted stock awarded under the Company's stock option and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant.

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

Effective October 1, 2005, the Company adopted SFAS 123R, which requires the measurement and recognition of compensation cost at fair value for all share-based payments, including stock options and stock-settled SARs. The Company has chosen to use the modified version of prospective application, as allowed by SFAS 123R. Using the modified prospective application, the Company recorded compensation cost for the portion of awards granted prior to October 1, 2005 for which the requisite service had not been rendered and recognized such compensation cost as the requisite service was rendered on or after October 1, 2005. Such compensation expense is based on the grant-date fair value of the awards as calculated for the Company's disclosure using a Binomial option-pricing model under SFAS 123. Any new awards, modifications to awards, repurchases of awards, or cancellations of awards subsequent to September 30, 2005 will follow the provisions of SFAS 123R, with compensation expense being calculated using the Black-Scholes-Merton closed form model. The Company has chosen the Black-Scholes-Merton closed form model since it is easier to administer than the Binomial option-pricing model. Furthermore, since the Company does not have complex stock-based compensation awards, it does not believe that compensation expense would be materially different under either model. There were 448,000, 317,000 and 700,000 stock options granted during the years ended September 30, 2007, 2006 and 2005, respectively. The Company granted 50,000 stock-settled SARs during the year ended September 30, 2007. There were no stock-settled SARs granted during the years ended September 30, 2006 and 2005. The accounting treatment for such stock-settled SARs is the same under SFAS 123R as the accounting for stock options under SFAS 123R. The Company also granted 25,000 and 16,000 restricted share awards (non-vested stock as defined by SFAS 123R) during the years ended September 30, 2007 and 2006, respectively. There were no restricted share awards granted during the year ended September 30, 2005. Stock-based compensation expense for the years ended September 30, 2007, 2006 and 2005 was approximately $3,727,000, $1,705,000, and $517,000, 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, 2007, 2006 and 2005 was approximately $1,488,000, $653,000 and $206,000, respectively. There were no capitalized stock-based compensation costs during the years ended September 30, 2007 and 2006.

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, 2007, the amount of compensation expense recognized by the Company using the non-substantive vesting approach was $280,000 ($182,000 net of tax) less than if the nominal vesting period approach had been used. 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 as opposed to the nominal vesting period 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. Pro forma stock-based compensation expense following the nominal vesting period approach is shown in the table below.

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 year ended September 30, 2005:

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

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

***Stock Options***

The total intrinsic value of stock options exercised during the years ended September 30, 2007, 2006 and 2005 totaled approximately $38.7 million, $30.9 million, and $19.8 million, respectively. For 2007, 2006 and 2005, the amount of cash received by the Company from the exercise of such stock options was approximately $26.0 million, $30.1 million, and $24.8 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, 2006, 2005, and 2004, the Company realized a tax benefit of $3.2 million, $0.9 million, and $1.1 million, respectively. For stock options exercised during the period of January 1, 2007 through September 30, 2007, the Company will realize a tax benefit of approximately $12.0 million in the quarter ended December 31, 2007. For stock options exercised during the period of January 1, 2006 through September 30, 2006, the Company realized a tax benefit of approximately $11.4 million in the quarter ended December 31, 2006. 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. The weighted average grant date fair value of options granted in 2007, 2006 and 2005 is $7.27 per share, $6.68 per share, and $4.59 per share, respectively. For the years ended September 30, 2007, 2006 and 2005, 327,501, 89,665 and 1,375,105 stock options became fully vested, respectively. The total fair value of these stock options was approximately $2.1 million, $0.4 million and $6.2 million, respectively, for the years ended September 30, 2007, 2006 and 2005. As of September 30, 2007, unrecognized compensation expense related to stock options totaled approximately $0.9 million, which will be recognized over a weighted average period of 10.6 months. For a summary of transactions during 2007 involving option shares for all plans, refer to Note E — Capitalization and Short-Term Borrowings.

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| Risk Free Interest Rate | 4.46% | 5.08% | 4.46% |
| Expected Life (Years) | 7.0 | 7.0 | 7.0 |
| Expected Volatility | 17.73% | 17.71% | 17.76% |
| Expected Dividend Yield (Quarterly) | 0.76% | 0.83% | 1.00% |

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

### *Stock-settled SARs*

There were no stock-settled SARs exercised during the years ended September 30, 2007, 2006 and 2005 as none of the stock-settled SARs granted have vested. The weighted average grant date fair value of stock-settled SARs granted in 2007 is $7.81 per share. There were no stock-settled SARs granted during 2006 or 2005. For the years ended September 30, 2007, 2006 and 2005, there were no stock-settled SARs that became fully vested. As of September 30, 2007, unrecognized compensation expense related to stock-settled SARs totaled approximately $0.3 million, which will be recognized over a weighted average period of 1.4 years. For a summary of transactions during 2007 involving stock-settled SARs for all plans, refer to Note E — Capitalization and Short-Term Borrowings.

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

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

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

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

***Restricted Share Awards***

The weighted average fair value of restricted share awards granted in 2007 and 2006 is $40.18 per share and $34.94 per share, respectively. There were no restricted share awards granted during 2005. As of September 30, 2007, unrecognized compensation expense related to restricted share awards totaled approximately $1.0 million, which will be recognized over a weighted average period of 1.7 years. For a summary of transactions during 2007 involving restricted share awards, refer to Note E — Capitalization and Short-Term Borrowings.

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

***New Accounting Pronouncements***

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes." FIN 48 clarifies the accounting for income taxes by prescribing a minimum probability threshold that a tax position must meet before a financial statement benefit is recognized. The minimum threshold is defined in FIN 48 as a tax position that is more likely than not to be sustained upon examination by the applicable taxing authority, including resolution of any related appeals or litigation processes, based on the technical merits of the position. If a tax benefit meets this threshold, it is measured and recognized based on an analysis of the cumulative probability of the tax benefit being ultimately sustained. The cumulative effect of applying FIN 48 at adoption, if any, is reported as an adjustment to opening retained earnings for the year of adoption. FIN 48 is effective for the first quarter of the Company's 2008 fiscal year and it is expected that this pronouncement will not have a material effect on the Company's 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. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company's fiscal year-end date will be adopted by the Company by the end of fiscal 2009. Currently, the Company measures its plan assets and benefit obligations using a June 30th measurement date. At September 30, 2007, in order to recognize the funded status of its pension and post-retirement benefit plans in accordance with SFAS 158, the Company recorded additional liabilities or reduced assets by a cumulative amount of $78.7 million ($71.1 million net of deferred tax benefits recognized for the portion recorded as an increase to Accumulated Other Comprehensive Loss). Of the $71.1 million recognized, $61.9 million was recorded as an increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments, $12.5 million (net of deferred tax benefits of $7.6 million) was recorded as an increase to Accumulated Other Comprehensive Loss, and $3.3 million was recorded as an increase to Other Regulatory

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

In February 2007, the FASB issued SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities — Including an Amendment of SFAS 115." SFAS 159 permits entities to choose to measure many financial instruments and certain other items at fair value that are not otherwise required to be measured at fair value under GAAP. A company that elects the fair value option for an eligible item will be required to recognize in current earnings any changes in that item's fair value in reporting periods subsequent to the date of adoption. SFAS 159 is effective as of the Company's first quarter of fiscal 2009. The Company is currently evaluating the impact, if any, that the adoption of SFAS 159 will have on its consolidated financial statements.

**Note B — Asset Retirement Obligations**

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

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

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

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

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

As a result of the implementation of FIN 47 as of September 30, 2006, the Company recorded additional asset retirement obligations of $23.2 million and corresponding long-lived plant assets, net of accumulated depreciation, of $3.5 million. These assets will be depreciated over their respective remaining depreciable life. The remaining $19.7 million represents the cumulative accretion and depreciation of the asset retirement obligations that would have been recognized if this interpretation had been in effect at the inception of the obligations. Of this amount, the Company recorded an increase to regulatory assets of $9.0 million and a reduction to cost of removal regulatory liability of $10.7 million. The cost of removal regulatory liability represents amounts collected from customers through depreciation expense in the Company's Utility and Pipeline and Storage segments. These removal costs are not a legal retirement obligation in accordance with SFAS 143. Rather, they represent a regulatory liability. However, SFAS 143 requires that such costs of removal be reclassified from accumulated depreciation to other regulatory liabilities. At September 30, 2007 and 2006, the costs of removal reclassified to other regulatory liabilities amounted to $91.2 million and $85.1 million, respectively.

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Balance at Beginning of Year | $77,392 | $41,411 | $32,292 |
| Additions — Adoption of FIN 47 | — | 23,234 | — |
| Liabilities Incurred and Revisions of Estimates | (932) | 11,244 | 8,343 |
| Liabilities Settled | (6,108) | (1,303) | (1,938) |
| Accretion Expense | 5,394 | 2,671 | 2,448 |
| Exchange Rate Impact | 193 | 135 | 266 |
| Balance at End of Year | $75,939 | $77,392 | $41,411 |

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 October 1, 2005.

## Note C — Regulatory Matters

### *Regulatory Assets and Liabilities*

The Company has recorded the following regulatory assets and liabilities:

| | At September 30 | |
|---|---|---|
| | 2007 | 2006 |
| | (Thousands) | |
| **Regulatory Assets(1):** | | |
| Pension and Post-Retirement Benefit Costs(2) (Note G) | $ 98,787 | $ 47,368 |
| Recoverable Future Taxes (Note D) | 83,954 | 79,511 |
| Environmental Site Remediation Costs(2) (Note H) | 20,738 | 12,937 |
| Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A) | 14,769 | 12,970 |
| Unamortized Debt Expense (Note A) | 8,470 | 8,399 |
| Asset Retirement Obligations(2) (Note B) | 8,315 | 9,018 |
| Recoverable Worker Compensation Expense(2) | 4,445 | 3,691 |
| Other(2) | 5,292 | 3,903 |
| Total Regulatory Assets | 244,770 | 177,797 |
| **Regulatory Liabilities**: | | |
| Cost of Removal Regulatory Liability (Note B) | 91,226 | 85,076 |
| New York Rate Settlements(3) | 27,964 | 40,881 |
| Pension and Post-Retirement Benefit Costs(3) (Note G) | 21,676 | 13,063 |
| Tax Benefit on Medicare Part D Subsidy(3) | 19,147 | 13,791 |
| Taxes Refundable to Customers (Note D) | 14,026 | 10,426 |
| Amounts Payable to Customers (See Regulatory Mechanisms in Note A) | 10,409 | 23,935 |
| Deferred Insurance Proceeds(3) | 7,422 | 7,516 |
| Other(3) | 450 | 205 |
| Total Regulatory Liabilities | 192,320 | 194,893 |
| Net Regulatory Position | $ 52,450 | $ (17,096) |

(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.

***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, 2007 and 2006 of $6.7 million and $19.8 million, respectively. Under the terms of its 2005 rate agreement, Distribution Corporation has been passing back that regulatory liability to rate payers since August 1, 2005. Further, the gross receipts tax surcharge that gave rise to the regulatory liability was eliminated from Distribution Corporation's tariff (New York State income taxes are now recovered as a component of base rates).

Cost Mitigation Reserve ("CMR") — The CMR is a regulatory liability that can be used to offset certain expense items specified in Distribution Corporation's rate settlements. The source of the CMR is principally the accumulation of certain refunds from upstream pipeline companies. During 2005, under the terms of the 2005 rate agreement, Distribution Corporation transferred the remaining balance in a generic restructuring reserve (which had been established in a prior rate settlement) and the balances it had accumulated under various earnings sharing mechanisms to the CMR. The balance in the CMR at September 30, 2007 and 2006 amounted to $7.4 million and $7.6 million, respectively.

Other — The 2005 agreement also established a reserve to fund area development projects. The balance in the area development projects reserve at September 30, 2007 and 2006 amounted to $3.6 million and $3.9 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 $10.3 million and $9.6 million at September 30, 2007 and 2006, respectively.

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

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

***Deferred Insurance Proceeds***

In 2006, 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 ratepayers funded the premiums on the former insurance policies. Deferred insurance proceeds amounted to $7.4 million at September 30, 2007.

***Recoverable Worker Compensation Expense***

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

### 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 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Current Income Taxes — | | | |
| Federal | $ 99,608 | $ 65,593 | $ 45,571 |
| State | 21,700 | 13,511 | 14,413 |
| Foreign | 22 | 2,212 | 4,104 |
| Deferred Income Taxes — | | | |
| Federal | 39,340 | 19,111 | 27,412 |
| State | 10,751 | 9,024 | 2,280 |
| Foreign | 2,756 | (33,365) | 10,120 |
| | 174,177 | 76,086 | 103,900 |
| Deferred Investment Tax Credit | (697) | (697) | (697) |
| Total Income Taxes | $173,480 | $ 75,389 | $103,203 |
| Presented as Follows: | | | |
| Other Income | $ (697) | $ (697) | $ (697) |
| Income Tax Expense — Continuing Operations | 131,813 | 108,245 | 85,621 |
| Discontinued Operations — | | | |
| Income From Operations | 2,792 | (32,159) | 16,667 |
| Gain on Disposal | 39,572 | — | 1,612 |
| Total Income Taxes | $173,480 | $ 75,389 | $103,203 |

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| U.S. | $496,074 | $293,887 | $223,113 |
| Foreign | 14,861 | (80,407) | 69,578 |
| | $510,935 | $213,480 | $292,691 |

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 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35% | $178,827 | $74,718 | $102,442 |
| Increase in Taxes Resulting from: | | | |
| State Income Taxes | 21,093 | 14,648 | 10,850 |
| Foreign Tax Differential | (20,980) | (3,718) | (4,845) |
| Reversal of Capital Loss Valuation Allowance | — | (2,877) | — |
| Miscellaneous | (5,460) | (7,382) | (5,244) |
| Total Income Taxes | $173,480 | $75,389 | $103,203 |

The foreign tax differential amount shown above for 2007 includes tax effects relating to the gain on disposition of a foreign subsidiary. Also, the foreign tax differential amount shown above for 2006 includes a $5.1 million deferred tax benefit relating to additional future tax deductions forecasted in Canada and the amount for 2005 includes tax effects relating to the disposition of a foreign subsidiary. 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 | |
|---|---|---|
| | 2007 | 2006 |
| | (Thousands) | |
| Deferred Tax Liabilities: | | |
| Property, Plant and Equipment | $ 612,648 | $569,677 |
| Other | 61,616 | 37,865 |
| Total Deferred Tax Liabilities | 674,264 | 607,542 |
| Deferred Tax Assets: | | |
| Other | (107,458) | (95,445) |
| Total Deferred Tax Assets | (107,458) | (95,445) |
| Total Net Deferred Income Taxes | $ 566,806 | $512,097 |
| Presented as Follows: | | |
| Net Deferred Tax Asset — Current | $ (8,550) | $ (23,402) |
| Net Deferred Tax Asset — Non-Current | — | (9,003) |
| Net Deferred Tax Liability — Non-Current | 575,356 | 544,502 |
| Total Net Deferred Income Taxes | $ 566,806 | $512,097 |

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 $14.0 million and $10.4 million at September 30, 2007 and 2006, 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 $84.0 million and $79.5 million at September 30, 2007 and 2006, respectively.

## 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, 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 | 30,416 |
| Net Income Available for Common Stock | | | | 337,455 | |
| Dividends Declared on Common Stock ($1.22 Per Share) | | | | (101,496) | |
| Other Comprehensive Loss, Net of Tax | | | | | (24,137) |
| Adjustment to Recognize the Funded Position of the Pension and Other Post-Retirement Benefit Plans | | | | | (12,482) |
| Share-Based Payment Expense(2) | | | 3,727 | | |
| Common Stock Issued Under Stock and Benefit Plans(1) | 1,367 | 1,367 | 30,193 | | |
| Share Repurchases | (1,309) | (1,309) | (8,565) | (38,196) | |
| Balance at September 30, 2007 | 83,461 | $83,461 | $569,085 | $ 983,776(3) | $ (6,203) |

(1) Paid in Capital includes tax benefits of $13.7 million, $6.5 million and $3.7 million for September 30, 2007, 2006 and 2005, respectively, associated with the exercise of stock options.

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

(3) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2007, $880.6 million of accumulated earnings was free of such limitations.

### *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 2007, the Company issued 2,070,613 original issue shares of common stock as a result of stock option exercises and 25,000 original issue shares for restricted stock awards (non-vested stock as defined in SFAS 123R). Holders of stock options or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During 2007, 731,793 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. There were also 6,000 restricted stock award shares forfeited during 2007.

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 9,146 original issue shares of common stock to the non-employee directors of the Company during 2007.

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 2007, the Company repurchased 1,308,328 shares for $48.1 million under this program, funded with cash provided by operating activities and/or through the use of the Company's lines of credit. Since the repurchase program was implemented, the Company has repurchased 3,834,878 shares for $133.2 million.

### *Shareholder Rights Plan*

In 1996, the Company's Board of Directors adopted a shareholder rights plan (Plan). The Plan has been amended three times since it was adopted and is now embodied in an Amended and Restated Rights Agreement effective September 1, 2007, which is an Exhibit to this Annual Report and Form 10-K.

The holders of the Company's common stock have one right (Right) for each of their shares. Each Right, 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 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 earlier than that date, they are exchanged or redeemed or the Plan is amended to extend the expiration 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, stock-settled SARs, restricted stock, performance units or performance shares. Stock options and stock-settled SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no option or stock-settled SAR is exercisable less than one year or more than ten years after the date of each grant.

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, 2006 | 9,016,254 | $24.69 | | |
| Granted in 2007 | 448,000 | $39.48 | | |
| Exercised in 2007 | (2,070,613) | $23.65 | | |
| Forfeited in 2007 | (33,600) | $25.39 | | |
| Outstanding at September 30, 2007 | 7,360,041 | $25.89 | 3.96 | $154,007 |
| Option shares exercisable at September 30, 2007 | 6,875,041 | $24.99 | 3.62 | $150,038 |
| Option shares available for future grant at September 30, 2007(1) | 1,075,397 | | | |

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

The following table summarizes information about options outstanding at September 30, 2007:

| | Options Outstanding | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Price | Number Outstanding at 9/30/07 | Weighted Average Remaining Contractual Life | Weighted Average Exercise Price | Number Exercisable at 9/30/07 | Weighted Average Exercise Price |
| $20.60-$24.72 | 4,233,174 | 2.8 | $22.72 | 4,213,174 | $22.73 |
| $24.73-$28.84 | 2,361,867 | 4.4 | $27.72 | 2,361,867 | $27.72 |
| $28.85-$32.96 | — | — | — | — | — |
| $32.97-$37.08 | 300,000 | 8.6 | $35.11 | 300,000 | $35.11 |
| $37.09-$41.20 | 465,000 | 9.2 | $39.39 | — | — |

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

| | Number of Shares Subject to Option | Weighted Average Exercise Price | Weighted Average Remaining Contractual Life (Years) | Aggregate Intrinsic Value |
|---|---|---|---|---|
| | | | | (In thousands) |
| Outstanding at September 30, 2006 | — | $ — | | |
| Granted in 2007 | 50,000 | $41.20 | | |
| Exercised in 2007 | — | $ — | | |
| Forfeited in 2007 | — | $ — | | |
| Outstanding at September 30, 2007 | 50,000 | $41.20 | 9.45 | $281 |
| Stock-settled SARs exercisable at September 30, 2007 | — | — | — | $ — |

The following table summarizes information about stock-settled SARs outstanding at September 30, 2007:

| | Stock-Settled SARs Outstanding | | | Stock-Settled SARs Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Price | Number Outstanding at 9/30/07 | Weighted Average Remaining Contractual Life | Weighted Average Exercise Price | Number Exercisable at 9/30/07 | Weighted Average Exercise Price |
| $37.09-$41.20 | 50,000 | 9.5 | $41.20 | — | — |

***Restricted Share Awards***

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

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

| | Number of Restricted Share Awards | Weighted Average Fair Value per Award |
|---|---|---|
| Restricted Share Awards Outstanding at September 30, 2006 | 42,328 | $28.44 |
| Granted in 2007 | 25,000 | $40.18 |
| Vested in 2007 | (25,000) | $24.50 |
| Forfeited in 2007 | (6,000) | $34.94 |
| Restricted Share Awards Outstanding at September 30, 2007 | 36,328 | $38.16 |

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2007 will lapse as follows: 2008 — 2,500 shares; 2009 — 2,500 shares; 2010 — 28,828 shares; and 2011 — 2,500 shares.

***Redeemable Preferred Stock***

As of September 30, 2007, 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 2007 | At September 30 2006 |
|---|---|---|
| | (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 6.5% due March 2013 to September 2022(2) | 250,000 | 346,665 |
| | 999,000 | 1,095,665 |
| Other Notes: | | |
| Secured(3) | — | 22,766 |
| Unsecured | 24 | 169 |
| Total Long-Term Debt | 999,024 | 1,118,600 |
| Less Current Portion | 200,024 | 22,925 |
| | $799,000 | $1,095,675 |

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

(2) At September 30, 2006, $96,665,000 of the 6.5% unsecured notes were redeemable at par at any time after September 15, 2006. On April 30, 2007, the Company redeemed these notes for $96.3 million, plus accrued interest.

(3) On December 8, 2006, the Company repaid these notes for $22.8 million. As such, the notes were classified as Current Portion of Long-Term Debt on the Company's Consolidated Balance Sheet at September 30, 2006. These notes constituted "project financing" that was secured by the various project documentation and natural gas transportation contracts related to the Empire State Pipeline. The interest rate on these notes was a variable rate based on LIBOR.

As of September 30, 2007, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $200.0 million in 2008, $100.0 million in 2009, zero in 2010, $200.0 million in 2011, $150.0 million in 2012, and $349.0 million thereafter.

### *Short-Term Borrowings*

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. As for the former, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $455.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or replaced by similar lines. The total amount available to be issued under the Company's commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million that extends through September 30, 2010.

At September 30, 2007 and 2006, 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, 2007, the Company's debt to capitalization ratio (as calculated under the facility) was .38. The constraints specified in the committed credit facility would permit an additional $2.02 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, 2007, the Company would have been permitted to issue up to a maximum of $1.4 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 40%) of the Company's long-term debt (as of September 30, 2007) was issued contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest or any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fail to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2007, 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 | | | |
|---|---|---|---|---|
| | 2007 Carrying Amount | 2007 Fair Value | 2006 Carrying Amount | 2006 Fair Value |
| | (Thousands) | | | |
| Long-Term Debt | $999,024 | $1,024,417 | $1,118,600 | $1,148,089 |

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 $54.7 million and $62.5 million at September 30, 2007 and 2006, respectively. The fair value of the equity mutual fund was $14.7 million and $12.9 million at September 30, 2007 and 2006, respectively. The gross unrealized gain on this equity mutual fund was $2.2 million and $1.0 million at September 30, 2007 and 2006, 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 $16.3 million and $12.7 million at September 30, 2007 and 2006, respectively. The gross unrealized gain on this stock was $13.8 million and $10.3 million at September 30, 2007 and 2006, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

### *Derivative Financial Instruments*

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

Under the price swap agreements, the Company receives monthly payments from (or makes payments to) other parties based upon the difference between a fixed price and a variable price as specified by the agreement. The variable price is either a crude oil or natural gas price quoted on the NYMEX or a quoted natural gas price in various national natural gas publications. The majority of these derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment and the All Other category. The Energy Marketing segment accounts for these derivative financial instruments as fair value hedges and uses them to hedge against falling prices, a risk to which they are exposed on their fixed price gas purchase commitments. The Energy Marketing segment also uses these derivative financial instruments to hedge against rising prices, a risk to which they are exposed on their fixed price sales commitments. At September 30, 2007, the Company had natural gas price swap agreements covering a notional amount of 13.2 Bcf extending through 2009 at a weighted average fixed rate of $8.20 per Mcf. Of this amount, 0.5 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $6.94 per Mcf. The remaining 12.7 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $8.24 per Mcf. At September 30, 2007, the Company would have received a net $2.8 million to terminate the price swap agreements. The Company also had crude oil price swap agreements covering a notional amount of 1,485,000 bbls extending through 2009 at a weighted average fixed rate of $57.35 per bbl. At September 30, 2007, the Company would have had to pay a net $11.2 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 various national natural gas publications. 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, 2007, the Company had no cost collars on natural gas covering a notional amount of 1.4 Bcf extending through 2008 with a weighted average floor price of $8.83 per Mcf and a weighted average ceiling price of $16.45 per Mcf. At September 30, 2007, the Company would have received $1.9 million to terminate the no cost collars.

At September 30, 2007, the Company had long (purchased) futures contracts covering 8.7 Bcf of gas extending through 2012 at a weighted average contract price of $8.72 per Mcf. They are accounted for as fair value hedges and are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with residential, commercial and industrial customers. The Company would have had to pay $6.0 million to terminate these futures contracts at September 30, 2007.

At September 30, 2007, the Company had short (sold) futures contracts covering 5.9 Bcf of gas extending through 2009 at a weighted average contract price of $9.67 per Mcf. Of this amount, 3.9 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 2.0 Bcf is accounted for as fair value hedges used to hedge against falling prices on their fixed price gas purchasing commitments and hedge against decreases in natural gas prices associated with the eventual sale of gas in storage. The Company would have received $8.2 million to terminate these futures contracts at September 30, 2007.

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 many of the parent companies of the respective counterparties to its derivative financial instruments. At September 30, 2007, the Company used nine counterparties for its over the counter derivative financial instruments. At September 30, 2007, no individual counterparty represented greater than 32% 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, 2007.

In August 2007, the Exploration and Production segment's investment in Canada was sold. Of the $232.1 million in net proceeds received, $58.0 million was placed in escrow (denominated in Canadian dollars) pending receipt of a tax clearance certificate from the Canadian government. To hedge against foreign currency exchange risk, the Company entered into a $58.0 million forward contract to sell Canadian dollars. At September 30, 2007, due to the increase in the strength of the Canadian dollar versus the U.S. dollar, the Company had a $2.7 million derivative liability related to the collar. The Company records gains or losses associated with this forward contract directly to the income statement.

## 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 73% of the employees of the Company. The Company provides health care and life insurance benefits for a majority of its 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, subject to limitations contained in the Internal Revenue Code and regulations. 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, 2007, 2006 and 2005, respectively.

| | Retirement Plan | | | Other Post-Retirement Benefits | | |
|---|---|---|---|---|---|---|
| | Year Ended September 30 | | | Year Ended September 30 | | |
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| | (Thousands) | | | | | |
| **Change in Benefit Obligation** | | | | | | |
| Benefit Obligation at Beginning of Period | $732,207 | $ 825,204 | $ 693,532 | $445,931 | $ 546,273 | $ 422,003 |
| Service Cost | 12,898 | 16,416 | 13,714 | 5,614 | 8,029 | 6,153 |
| Interest Cost | 44,350 | 40,196 | 42,079 | 27,198 | 26,804 | 25,783 |
| Plan Participants' Contributions | — | — | — | 1,566 | 1,559 | 1,017 |
| Retiree Drug Subsidy Receipts | — | — | — | 1,325 | — | — |
| Actuarial (Gain) Loss | (2,986) | (108,112) | 115,128 | (14,450) | (115,052) | 110,663 |
| Benefits Paid | (43,950) | (41,497) | (39,249) | (22,639) | (21,682) | (19,346) |
| **Benefit Obligation at End of Period** | $742,519 | $ 732,207 | $ 825,204 | $444,545 | $ 445,931 | $ 546,273 |
| **Change in Plan Assets** | | | | | | |
| Fair Value of Assets at Beginning of Period | $664,521 | $ 616,462 | $ 573,366 | $325,624 | $ 271,636 | $ 229,485 |
| Actual Return on Plan Assets | 119,662 | 68,649 | 56,201 | 65,552 | 34,785 | 20,577 |
| Employer Contributions | 16,488 | 20,907 | 26,144 | 42,268 | 39,326 | 39,903 |
| Employer Contributions During Period from Measurement Date to Fiscal Year End | 8,423 | — | — | — | — | — |
| Plan Participants' Contributions | — | — | — | 1,566 | 1,559 | 1,017 |
| Benefits Paid | (43,950) | (41,497) | (39,249) | (22,639) | (21,682) | (19,346) |
| **Fair Value of Assets at End of Period** | $765,144 | $ 664,521 | $ 616,462 | $412,371 | $ 325,624 | $ 271,636 |
| **Reconciliation of Funded Status** | | | | | | |
| Funded Status | $ 22,625 | $ (67,686) | $(208,742) | $(32,174) | $(120,307) | $(274,637) |
| Unrecognized Net Actuarial Loss | — | 107,626 | 257,553 | — | 54,487 | 205,423 |
| Unrecognized Transition Obligation | — | — | — | — | 49,890 | 57,017 |
| Unrecognized Prior Service Cost | — | 7,185 | 8,142 | — | 12 | 17 |
| Net Amount Recognized at End of Period | $ 22,625 | $ 47,125 | $ 56,953 | $(32,174) | $ (15,918) | $ (12,180) |

| | Retirement Plan | | | Other Post-Retirement Benefits | | |
|---|---|---|---|---|---|---|
| | Year Ended September 30 | | | Year Ended September 30 | | |
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| | (Thousands) | | | | | |
| **Amounts Recognized in the Balance Sheets Consist of:** | | | | | | |
| Accrued Benefit Liability | $ — | $ — | $(117,103) | $(70,555) | $ (32,918) | $ (26,584) |
| Prepaid Benefit Cost | 22,625 | 47,125 | — | 38,381 | 17,000 | 14,404 |
| Intangible Assets | — | — | 8,142 | — | — | — |
| Accumulated Other Comprehensive Loss from Additional Minimum Pension Liability Adjustment (Pre-Tax) | — | — | 165,914 | — | — | — |
| Net Amount Recognized at End of Period | $ 22,625 | $ 47,125 | $ 56,953 | $(32,174) | $ (15,918) | $ (12,180) |
| **Weighted Average Assumptions Used to Determine Benefit Obligation at September 30** | | | | | | |
| Discount Rate | 6.25% | 6.25% | 5.00% | 6.25% | 6.25% | 5.00% |
| Expected Return on Plan Assets | 8.25% | 8.25% | 8.25% | 8.25% | 8.25% | 8.25% |
| Rate of Compensation Increase | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% | 5.00% |
| **Components of Net Periodic Benefit Cost** | | | | | | |
| Service Cost | $ 12,898 | $ 16,416 | $ 13,714 | $ 5,614 | $ 8,029 | $ 6,153 |
| Interest Cost | 44,350 | 40,196 | 42,079 | 27,198 | 26,804 | 25,783 |
| Expected Return on Plan Assets | (51,235) | (49,943) | (49,545) | (26,960) | (22,302) | (18,862) |
| Amortization of Prior Service Cost | 882 | 957 | 1,029 | 4 | 4 | 4 |
| Amortization of Transition Amount | — | — | — | 7,127 | 7,127 | 7,127 |
| Recognition of Actuarial Loss(1) | 13,528 | 23,108 | 10,473 | 8,214 | 23,402 | 12,467 |
| Net Amortization and Deferral for Regulatory Purposes | 1,211 | (6,409) | 1,988 | 16,220 | (11,084) | (410) |
| Net Periodic Benefit Cost | $ 21,634 | $ 24,325 | $ 19,738 | $ 37,417 | $ 31,980 | $ 32,262 |
| Other Comprehensive (Income) Loss (Pre-Tax) Attributable to Change In Additional Minimum Liability Recognition | $ — | $(165,914) | $ 83,379 | $ — | $ — | $ — |
| Accumulated Other Comprehensive Loss (Pre-Tax) Attributable to Adoption of SFAS 158 | $ 11,256 | NA | NA | $ 778 | NA | NA |
| **Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost 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% |

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

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

| | Before Application of SFAS 158(1) | Consolidated SFAS 158 Impact | After Application of SFAS 158 |
|---|---|---|---|
| | | (Thousands) | |
| **Qualified Retirement Plan** | | | |
| Reduction in Prepaid Pension and Post-Retirement Benefit Costs | $ 51,612 | $(28,987) | $ 22,625 |
| Increase in Other Regulatory Assets Related to SFAS 158 | $ — | $ 17,731 | $ 17,731 |
| Reduction in Accumulated Other Comprehensive Income | $ — | $ 7,008 | $ 7,008 |
| Reduction in Deferred Income Taxes (under Deferred Credits) | $ — | $ 4,248 | $ 4,248 |

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

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

The amounts recognized in accumulated other comprehensive loss, regulatory assets, and regulatory liabilities in fiscal 2007, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2008 are presented in the table below:

| | Retirement Plan | Other Post-Retirement Benefits | Non-Qualified Benefit Plan |
|---|---|---|---|
| | | (Thousands) | |
| **Amounts Recognized In Accumulated Other Comprehensive Loss, Regulatory Assets and Regulatory Liabilities(1)** | | | |
| Net Actuarial Gain/(Loss) | $(22,684) | $ 6,768 | $(13,605) |
| Transition Obligation | — | (42,763) | — |
| Prior Service Cost | (6,303) | (8) | (116) |
| Net Amount Recognized | $(28,987) | $(36,003) | $(13,721) |
| **Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)** | | | |
| Net Actuarial Gain/(Loss) | $(11,064) | $ (2,927) | $ (1,218) |
| Transition Obligation | — | (7,127) | — |
| Prior Service Cost | (808) | (4) | (106) |
| Net Amount Expected to be Recognized | $(11,872) | $(10,058) | $ (1,324) |

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

In accordance with the provisions of SFAS 87, the Company recorded an additional minimum pension liability at September 30, 2005 representing the excess of the accumulated benefit obligation over the fair value of plan assets plus accrued amounts previously recorded. An intangible asset, 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 related to the additional minimum pension liability adjustment at September 30, 2006 and 2005 are shown in the table above. At September 30, 2007, prior to recognizing the impact of adopting SFAS 158, there was no additional minimum pension liability adjustment recorded since the fair value of the plan assets exceeded the accumulated benefit obligation. The projected benefit obligation, accumulated benefit obligation and fair value of assets for the Retirement Plan were as follows:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Projected Benefit Obligation | $742,519 | $732,207 | $825,204 |
| Accumulated Benefit Obligation | $672,340 | $660,026 | $733,565 |
| Fair Value of Plan Assets | $765,144 | $664,520 | $616,462 |

In 2007, other actuarial experience decreased the projected benefit obligation for the Retirement Plan by $3.0 million. There was no change to the discount rate used to estimate the projected benefit obligation for the Retirement Plan during 2007. The effect of the discount rate change for the Retirement Plan in 2006 was to decrease the projected benefit obligation of the Retirement Plan by $113.1 million. The discount rate change for the Retirement Plan in 2005 caused the projected benefit obligation to increase by $113.0 million.

The Company made cash contributions totaling $24.9 million to the Retirement Plan during the year ended September 30, 2007. The Company expects that the annual contribution to the Retirement Plan in 2008 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: $46.7 million in 2008; $47.8 million in 2009; $49.0 million in 2010; $50.1 million in 2011; $51.3 million in 2012; and $283.3 million in the five years thereafter.

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 $0.4 million through September 30, 2007 (with $0.2 million and $0.1 million of costs occurring in 2007 and 2006, respectively). Costs associated with the Company's contributions to the Tax-Deferred Savings Plans were $4.1 million, $4.1 million, and $4.2 million for the years ended September 30, 2007, 2006 and 2005, 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 $5.5 million, $5.4 million and $4.3 million in 2007, 2006 and 2005, respectively. For 2007, accumulated other comprehensive loss (pre-tax) of $8.0 million was recognized attributable to the adoption of SFAS 158. There were no amounts recognized in other comprehensive income (loss) attributable to the recognition of an additional minimum liability for 2006 and 2005. The accumulated benefit obligation for this plan was $28.8 million and $26.5 million at September 30, 2007 and 2006, respectively. The projected benefit obligation for the plan was $43.8 million and $44.5 million at September 30, 2007 and 2006, respectively. The actuarial valuations for this plan were determined based on a discount rate of 6.25%, 6.25% and 5.0% as of September 30, 2007, 2006 and 2005, respectively; a rate of compensation increase of 10.0% as of September 30, 2007, 2006 and 2005; and an expected long-term rate of return on plan assets of 8.25% at September 30, 2007, 2006 and 2005.

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

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

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

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

| | Benefit Payments | Subsidy Receipts |
|---|---|---|
| First Year | $ 23,990,000 | $ (1,522,000) |
| Second Year | $ 25,973,000 | $ (1,745,000) |
| Third Year | $ 28,007,000 | $ (1,954,000) |
| Fourth Year | $ 29,917,000 | $ (2,154,000) |
| Fifth Year | $ 31,406,000 | $ (2,401,000) |
| Next Five Years | $176,333,000 | $(15,391,000) |

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 10.0% 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 9.0% 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% in 2006 and was assumed to gradually decline to 5.0% by the year 2014. In 2007, the rate of increase for Pre age 65 participants was 8.0% and was assumed to gradually decline to 5.0% by the year 2014. The rate of increase for the Post age 65 participants was 6.67% in 2007 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 12.5% for 2005, 11.0% for 2006, 10.0% for 2007, 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 6.0% for 2005, 5.25% for 2006, and 7.0% for 2007. The annual rate of increase for the Medicare Part B Reimbursement is expected to gradually decline to 5.0% by the year 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, 2007 would increase by $55.6 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 2007 by $4.9 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, 2007 would decrease by $46.6 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2007 by $4.0 million.

The Company made cash contributions including payments made directly to participants totaling $42.3 million to the Post-Retirement Plan during the year ended September 30, 2007. The Company expects that the annual contribution to the Post-Retirement Plan in 2008 will be in the range of $25.0 million to $35.0 million.

The Company's Retirement Plan weighted average asset allocations at September 30, 2007, 2006 and 2005 by asset category are as follows:

| Asset Category | Target Allocation 2008 | Percentage of Plan Assets at September 30 2007 | 2006 | 2005 |
|---|---|---|---|---|
| Equity Securities | 60-75% | 70% | 67% | 63% |
| Fixed Income Securities | 20-35% | 24% | 26% | 28% |
| Other | 0-15% | 6% | 7% | 9% |
| Total | | 100% | 100% | 100% |

The Company's Post-Retirement Plan weighted average asset allocations at September 30, 2007, 2006 and 2005 by asset category are as follows:

| Asset Category | Target Allocation 2008 | Percentage of Plan Assets at September 30 2007 | 2006 | 2005 |
|---|---|---|---|---|
| Equity Securities | 85-100% | 95% | 95% | 92% |
| Fixed Income Securities | 0-15% | 1% | 1% | 2% |
| Other | 0-15% | 4% | 4% | 6% |
| 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, 2007. 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). The Company also utilizes a yield curve model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year's anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments.

## Note H — Commitments and Contingencies

### *Environmental Matters*

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

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. At September 30, 2007, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $12.1 million to $15.8 million. The minimum estimated liability of $12.1 million has been recorded on the Consolidated Balance Sheet at September 30, 2007. 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 four former manufactured gas plant sites in New York and Pennsylvania. The Company continues to be responsible for future ongoing maintenance at one site. At a second site, remediation is complete and long-term maintenance and monitoring activities are ongoing. A third site, which allegedly contains, among other things, manufactured gas plant waste, is in the investigation stage.

At a fourth former manufactured gas plant site, the Company received, in 1998 and again in October 1999, notice that the NYDEC believes the Company is responsible for contamination discovered at the site located in New York for which the Company had not been named as a PRP. In February 2007, the NYDEC identified the Company as a PRP for the site and issued a proposed remedial action plan. The NYDEC estimated clean-up costs under its proposed remedy to be $8.9 million if implemented. Although the Company commented to the NYDEC that the proposed remedial action plan contained a number of material errors, omissions and procedural defects, the NYDEC, in a March 2007 Record of Decision, selected the remedy it had previously proposed. In July 2007, the Company appealed the NYDEC's Record of Decision to the New York State Supreme Court, Albany County. The Company believes that a negotiated resolution with the NYDEC regarding the site remains possible.

*(ii) Third Party Waste Disposal Sites*

The Company was identified by the NYDEC or the EPA 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 were alleged to have contributed to the materials that may have been collected at such waste disposal sites by the site operators. The remediation was 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. In September 2007, the reallocation process was concluded with respect to both of these sites whereby the Company was released from any future liability related to these sites, and was allocated a refund of approximately $0.5 million as a result of the conclusion of the cost reallocation process.

*(iii) Other*

In June 2007, the NYDEC notified the Company, as well as a number of other companies, of their liability with respect to a remedial account at a waste disposal site in New York. The notification identified the Company as one of approximately 400 other companies considered to be PRPs related to this site and requested that the remedy the NYDEC proposed in a Record of Decision issued in March 2006 be performed. The estimated clean-up costs under the remedy selected by the NYDEC are estimated to be approximately $13.0 million if implemented. The Company is in the process of organizing a group with the other PRPs and negotiating an Order on Consent with the NYDEC to perform the remedy. The Company has not been able to reasonably estimate the probability or extent of its share of potential liability at this site.

***Other***

The Company, in its Utility segment, Energy Marketing segment, and All Other category, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. Substantially all of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $766.5 million in 2008, $114.5 million in 2009, $50.8 million in 2010, $22.1 million in 2011, $8.8 million in 2012, and $23.3 million thereafter. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of buildings, vehicles, construction tools, meters, computer equipment and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $6.7 million in 2008, $5.8 million in 2009, $4.4 million in 2010, $2.9 million in 2011, $2.6 million in 2012, and $13.1 million thereafter.

The Company has entered into several contractual commitments associated with the construction of the Empire Connector project, including the pipeline construction itself and construction of a compressor station, as well as other contractual commitments for engineering and consulting services. The Empire Connector is scheduled to go in service by November 2008. As of September 30, 2007, the future contractual commitments related to the construction of the Empire Connector during the next two years are as follows: $118.3 million in 2008 and $0.6 million in 2009.

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

## Note I — Discontinued Operations

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

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| Operating Revenues | $ 50,495 | $ 71,984 | $62,775 |
| Operating Expenses | 33,306 | 151,532 | 40,600 |
| Operating Income (Loss) | 17,189 | (79,548) | 22,175 |
| Interest Income | 1,082 | 866 | 260 |
| Income (Loss) before Income Taxes | 18,271 | (78,682) | 22,435 |
| Income Tax Expense (Benefit) | 2,792 | (32,159) | 7,357 |
| Income (Loss) from Discontinued Operations | 15,479 | (46,523) | 15,078 |
| Gain on Disposal, Net of Taxes of $39,572 | 120,301 | — | — |
| Income (Loss) from Discontinued Operations | $135,780 | $ (46,523) | $15,078 |

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 |
|---|---|
| | (Thousands) |
| Operating Revenues | $124,840 |
| Operating Expenses | 103,155 |
| Operating Income | 21,685 |
| Other Income | 2,048 |
| Interest Expense | (558) |
| Income before Income Taxes and Minority Interest | 23,175 |
| Income Tax Expense | 10,331 |
| Minority Interest, Net of Taxes | 2,645 |
| Income from Discontinued Operations | 10,199 |
| Gain on Disposal, Net of Taxes of $1,612 | 25,774 |
| Income from Discontinued Operations | $ 35,973 |

**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 transports gas to major industrial companies, utilities (including Distribution Corporation) and power producers.

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

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.

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. All Czech Republic operations have been reported as discontinued operations. Any remaining international activity has been included in corporate operations.

| | Year Ended September 30, 2007 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | Total Consolidated |
| | (Thousands) | | | | | | | | |
| Revenue from External Customers | $1,106,453 | $130,410 | $ 324,037 | $413,612 | $ 58,897 | $2,033,409 | $ 5,385 | $ 772 | $2,039,566 |
| Intersegment Revenues | $ 14,271 | $ 81,556 | $ — | $ — | $ — | $ 95,827 | $ 8,726 | $(104,553) | $ — |
| Interest Income | $ (2,345) | $ 357 | $ 9,905 | $ 682 | $ 1,249 | $ 9,848 | $ 16 | $ (8,314) | $ 1,550 |
| Interest Expense | $ 28,190 | $ 9,623 | $ 51,743 | $ 263 | $ 3,265 | $ 93,084 | $ 2,687 | $ (21,296) | $ 74,475 |
| Depreciation, Depletion and Amortization | $ 40,541 | $ 32,985 | $ 78,174 | $ 33 | $ 4,709 | $ 156,442 | $ 785 | $ 692 | $ 157,919 |
| Income Tax Expense | $ 31,642 | $ 35,740 | $ 52,421 | $ 5,654 | $ 2,818 | $ 128,275 | $ 1,647 | $ 1,891 | $ 131,813 |
| Income from Unconsolidated Subsidiaries | $ — | $ — | $ — | $ — | $ — | $ — | $ 4,979 | $ — | $ 4,979 |
| Segment Profit: Income from Continuing Operations | $ 50,886 | $ 56,386 | $ 74,889 | $ 7,663 | $ 3,728 | $ 193,552 | $ 2,564 | $ 5,559 | $ 201,675 |
| Expenditures for Additions to Long-Lived Assets from Continuing Operations | $ 54,185 | $ 43,226 | $ 146,687 | $ 76 | $ 3,657 | $ 247,831 | $ 87 | $ (319) | $ 247,599 |

| | At September 30, 2007 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | (Thousands) | | | | | | | | |
| Segment Assets | $1,565,593 | $810,957 | $1,326,073 | $ 59,802 | $165,224 | $3,927,649 | $66,531 | $(105,768) | $3,888,412 |

| | Year Ended September 30, 2006 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | Total Consolidated |
| | (Thousands) | | | | | | | | |
| Revenue from External Customers | $1,265,695 | $132,921 | $ 274,896 | $497,069 | $ 65,024 | $2,235,605 | $ 3,304 | $ 766 | $2,239,675 |
| Intersegment Revenues | $ 15,068 | $ 81,431 | $ — | $ — | $ 5 | $ 96,504 | $ 9,444 | $(105,948) | $ — |
| Interest Income | $ 4,889 | $ 454 | $ 7,816 | $ 445 | $ 747 | $ 14,351 | $ 22 | $ (4,964) | $ 9,409 |
| Interest Expense | $ 26,174 | $ 6,620 | $ 50,457 | $ 227 | $ 3,095 | $ 86,573 | $ 2,555 | $ (10,547) | $ 78,581 |
| Depreciation, Depletion and Amortization | $ 40,172 | $ 36,876 | $ 67,122 | $ 53 | $ 6,495 | $ 150,718 | $ 789 | $ 492 | $ 151,999 |
| Income Tax Expense | $ 35,699 | $ 33,896 | $ 29,351 | $ 3,748 | $ 3,277 | $ 105,971 | $ 969 | $ 1,305 | $ 108,245 |
| Income from Unconsolidated Subsidiaries | $ — | $ — | $ — | $ — | $ — | $ — | $ 3,583 | $ — | $ 3,583 |
| Segment Profit (Loss): Income (Loss) from Continuing Operations | $ 49,815 | $ 55,633 | $ 67,494 | $ 5,798 | $ 5,704 | $ 184,444 | $ 359 | $ (189) | $ 184,614 |
| Expenditures for Additions to Long-Lived Assets from Continuing Operations | $ 54,414 | $ 26,023 | $ 166,535 | $ 16 | $ 2,323 | $ 249,311 | $ 85 | $ 2,995 | $ 252,391 |

| | At September 30, 2006 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | (Thousands) | | | | | | | | |
| Segment Assets | $1,498,442 | $767,889 | $1,209,969(1) | $ 81,374 | $159,421 | $3,717,095 | $64,287 | $ (17,634) | $3,763,748 |

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

| | Year Ended September 30, 2005 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Utility | Pipeline and Storage | Exploration and Production | Energy Marketing | Timber | Total Reportable Segments | All Other | Corporate and Intersegment Eliminations | Total Consolidated |
| | (Thousands) | | | | | | | | |
| Revenue from External Customers | $1,101,572 | $132,805 | $ 230,650 | $329,714 | $ 61,285 | $1,856,026 | $ 4,748 | $ — | $1,860,774 |
| Intersegment Revenues | $ 15,495 | $ 83,054 | $ — | $ — | $ 1 | $ 98,550 | $ 8,606 | $(107,156) | $ — |
| Interest Income | $ 4,111 | $ 76 | $ 4,401 | $ 783 | $ 438 | $ 9,809 | $ 19 | $ (3,592) | $ 6,236 |
| Interest Expense | $ 22,900 | $ 7,128 | $ 48,856 | $ 11 | $ 2,764 | $ 81,659 | $ 1,726 | $ (1,072) | $ 82,313 |
| Depreciation, Depletion and Amortization | $ 40,159 | $ 38,050 | $ 67,647 | $ 41 | $ 6,601 | $ 152,498 | $ 3,537 | $ 467 | $ 156,502 |
| Income Tax Expense (Benefit) | $ 23,102 | $ 39,068 | $ 20,996 | $ 3,210 | $ 2,271 | $ 88,647 | $ (1,425) | $ (1,601) | $ 85,621 |
| Income from Unconsolidated Subsidiaries | $ — | $ — | $ — | $ — | $ — | $ — | $ 3,362 | $ — | $ 3,362 |
| Significant Non-Cash Item: Impairment of Investment in Partnership | $ — | $ — | $ — | $ — | $ — | $ — | $ (4,158)(1) | $ — | $ (4,158) |
| Segment Profit (Loss): Income (Loss) from Continuing Operations | $ 39,197 | $ 60,454 | $ 35,581 | $ 5,077 | $ 5,032 | $ 145,341 | $ (2,616) | $ (4,288) | $ 138,437 |
| Expenditures for Additions to Long-Lived Assets from Continuing Operations | $ 50,071 | $ 21,099 | $ 83,972 | $ 58 | $ 18,894 | $ 174,094 | $ 463 | $ 618 | $ 175,175 |

| | At September 30, 2005 | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | (Thousands) | | | | | | | | |
| Segment Assets | $1,423,597 | $782,546 | $1,213,525(2) | $ 92,470 | $162,052 | $3,674,190 | $73,354 | $ 2,209 | $3,749,753 |

(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.

(2) Amount includes $204,892 of assets of SECI, which has been classified as discontinued operations as of September 30, 2007. (See Note I — Discontinued Operations).

| Geographic Information | For The Year Ended September 30 2007 | 2006 (Thousands) | 2005 |
|---|---|---|---|
| **Revenues from External Customers(1):** | | | |
| United States | $2,039,566 | $2,239,675 | $1,860,774 |

| | At September 30 2007 | 2006 (Thousands) | 2005 |
|---|---|---|---|
| **Long-Lived Assets:** | | | |
| United States | $3,334,274 | $3,181,769 | $2,978,680 |
| Assets of Discontinued Operations | — | 97,234 | 171,196 |
| | $3,334,274 | $3,279,003 | $3,149,876 |

(1) Revenue is based upon the country in which the sale originates. This table excludes revenues from Canadian discontinued operations of $50,495, $71,984 and $62,775 for September 30, 2007, 2006 and 2005, respectively.

### Note K — Investments in Unconsolidated Subsidiaries

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

During 2007, Horizon Power made capital contributions of $3.3 million to Seneca Energy. Seneca Energy is in the process of expanding its generating capacity from 11.2 megawatts to 17.6 megawatts.

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, 2007 and 2006 is as follows:

| | At September 30 2007 | 2006 (Thousands) |
|---|---|---|
| ESNE | $ 4,652 | $ 4,486 |
| Seneca Energy | 12,033 | 5,366 |
| Model City | 1,571 | 1,738 |
| | $18,256 | $11,590 |

### 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, 2007 | | | At September 30, 2006 |
|---|---|---|---|---|
| | Gross Carrying Amount | Accumulated Amortization | Net Carrying Amount | Net Carrying Amount |
| Intangible Assets Subject to Amortization: | | | | |
| Long-Term Transportation Contracts | $ 8,580 | $ (4,989) | $ 3,591 | $ 4,660 |
| Long-Term Gas Purchase Contracts | 31,864 | (6,619) | 25,245 | 26,838 |
| | $40,444 | $(11,608) | $28,836 | $31,498 |
| Aggregate Amortization Expense: | | | | |
| For the Year Ended September 30, 2007 | $ 2,662 | | | |
| For the Year Ended September 30, 2006 | $ 2,662 | | | |
| For the Year Ended September 30, 2005 | $ 2,662 | | | |

The gross carrying amount of intangible assets subject to amortization at September 30, 2007 remained unchanged from September 30, 2006. 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 in 2008, $0.5 million in 2009, and $0.4 million in 2010, 2011 and 2012. Amortization expense for the long-term gas purchase contracts is estimated to be $1.6 million annually for 2008, 2009, 2010, 2011 and 2012.

**Note M — Quarterly Financial Data (unaudited)**

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

| Quarter Ended | Operating Revenues | Operating Income | Income from Continuing Operations | Income (Loss) from Discontinued Operations | Net Income Available for Common Stock | Earnings from Continuing Operations per Common Share | | Earnings per Common Share | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | Basic | Diluted | Basic | Diluted |
| | (Thousands, except per common share amounts) | | | | | | | | |
| **2007** | | | | | | | | | |
| 9/30/2007 . . | $302,030 | $ 73,504 | $34,295 | $123,395(1) | $157,690(1) | $0.41 | $0.40 | $1.89 | $1.84 |
| 6/30/2007 . . | $448,779 | $ 83,933 | $41,212(2) | $ 5,586 | $ 46,798(2) | $0.49 | $0.48 | $0.56 | $0.55 |
| 3/31/2007 . . | $798,100 | $142,404 | $75,480(3) | $ 2,967 | $ 78,447(3) | $0.91 | $0.89 | $0.95 | $0.92 |
| 12/31/2006. . | $490,657 | $ 96,657 | $50,688(4) | $ 3,832 | $ 54,520(4) | $0.61 | $0.60 | $0.66 | $0.64 |
| **2006** | | | | | | | | | |
| 9/30/2006 . . | $280,506 | $ 56,865 | $28,585 | $(26,617)(5) | $ 1,968(5) | $0.34 | $0.33 | $0.02 | $0.02 |
| 6/30/2006 . . | $397,206 | $ 67,122 | $37,618(7) | $(37,507)(6) | $ 111(6)(7) | $0.45 | $0.44 | $ — | $ — |
| 3/31/2006 . . | $874,700 | $133,745 | $69,650 | $ 8,944(8) | $ 78,594(8) | $0.83 | $0.81 | $0.93 | $0.91 |
| 12/31/2005. . | $687,263 | $ 97,891 | $48,761(9) | $ 8,657 | $ 57,418(9) | $0.58 | $0.57 | $0.68 | $0.67 |

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

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

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

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

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

(6) Includes expense of $39.5 million related to the impairment of oil and gas producing properties.

(7) Includes income of $6.1 million related to income tax adjustments.

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

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

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

At September 30, 2007, there were 16,989 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, 2007 and 2006, are shown below:

| Quarter Ended | Price Range High | Price Range Low | Dividends Declared |
|---|---|---|---|
| **2007** | | | |
| 9/30/2007 | $47.00 | $40.95 | $.31 |
| 6/30/2007 | $47.87 | $42.75 | $.31 |
| 3/31/2007 | $43.79 | $36.94 | $.30 |
| 12/31/2006 | $40.21 | $35.02 | $.30 |
| **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 |

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

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

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

| | At September 30 2007 | At September 30 2006 |
|---|---|---|
| | (Thousands) | |
| Proved Properties(1) | $1,583,956 | $1,884,049 |
| Unproved Properties | 20,005 | 41,930 |
| | 1,603,961 | 1,925,979 |
| Less — Accumulated Depreciation, Depletion and Amortization | 627,073 | 929,921 |
| | $ 976,888 | $ 996,058 |

(1) Includes asset retirement costs of $40.9 million and $42.2 million at September 30, 2007 and 2006, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Following is a summary of costs excluded from amortization at September 30, 2007:

| | Total as of September 30, 2007 | Year Costs Incurred 2007 | 2006 | 2005 | Prior |
|---|---|---|---|---|---|
| | | (Thousands) | | | |
| Acquisition Costs | $20,005 | $5,957 | $12,485 | $1,099 | $464 |

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| **United States** | | | |
| Property Acquisition Costs: | | | |
| Proved | $ 2,621 | $ 5,339 | $ 287 |
| Unproved | 3,210 | 8,844 | 1,215 |
| Exploration Costs | 26,891 | 64,087 | 32,456 |
| Development Costs | 113,206 | 87,738 | 49,016 |
| Asset Retirement Costs | 2,139 | 10,965 | 8,051 |
| | 148,067 | 176,973 | 91,025 |
| **Canada — Discontinued Operations** | | | |
| Property Acquisition Costs: | | | |
| Proved | (1,404) | (427) | (1,551) |
| Unproved | (1,142) | 6,492 | 4,668 |
| Exploration Costs | 20,134 | 20,778 | 22,943 |
| Development Costs | 11,414 | 14,385 | 12,198 |
| Asset Retirement Costs | 167 | 279 | 292 |
| | 29,169 | 41,507 | 38,550 |
| **Total** | | | |
| Property Acquisition Costs: | | | |
| Proved | 1,217 | 4,912 | (1,264) |
| Unproved | 2,068 | 15,336 | 5,883 |
| Exploration Costs | 47,025 | 84,865 | 55,399 |
| Development Costs | 124,620 | 102,123 | 61,214 |
| Asset Retirement Costs | 2,306 | 11,244 | 8,343 |
| | $177,236 | $218,480 | $129,575 |

For the years ended September 30, 2007, 2006 and 2005, the Company spent $30.3 million, $55.6 million and $19.2 million, respectively, developing proved undeveloped reserves.

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (Thousands, except per Mcfe amounts) | | |
| **United States** | | | |
| Operating Revenues: | | | |
| Natural Gas (includes revenues from sales to affiliates of $325, $106 and $77, respectively) | $135,399 | $152,451 | $151,004 |
| Oil, Condensate and Other Liquids | 189,539 | 195,050 | 160,145 |
| Total Operating Revenues(1) | 324,938 | 347,501 | 311,149 |
| Production/Lifting Costs | 48,410 | 41,354 | 38,442 |
| Accretion Expense | 3,704 | 2,412 | 2,220 |
| Depreciation, Depletion and Amortization ($1.97, $1.74 and $1.58 per Mcfe of production) | 77,452 | 66,488 | 67,097 |
| Income Tax Expense | 78,928 | 88,104 | 74,110 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | 116,444 | 149,143 | 129,280 |
| **Canada — Discontinued Operations** | | | |
| Operating Revenues: | | | |
| Natural Gas | 39,114 | 54,819 | 49,275 |
| Oil, Condensate and Other Liquids | 10,313 | 13,985 | 12,875 |
| Total Operating Revenues(1) | 49,427 | 68,804 | 62,150 |
| Production/Lifting Costs | 14,846 | 14,628 | 12,683 |
| Accretion Expense | 249 | 258 | 228 |
| Depreciation, Depletion and Amortization ($1.67, $2.95 and $2.36 per Mcfe of production) | 12,787 | 27,439 | 23,108 |
| Impairment of Oil and Gas Producing Properties(2) | — | 104,739 | — |
| Income Tax Expense (Benefit) | 3,703 | (31,987) | 8,577 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | 17,842 | (46,273) | 17,554 |

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | (Thousands, except per Mcfe amounts) | | |
| **Total** | | | |
| Operating Revenues: | | | |
| Natural Gas (includes revenues from sales to affiliates of $325, $106 and $77, respectively) | 174,513 | 207,270 | 200,279 |
| Oil, Condensate and Other Liquids | 199,852 | 209,035 | 173,020 |
| Total Operating Revenues(1) | 374,365 | 416,305 | 373,299 |
| Production/Lifting Costs | 63,256 | 55,982 | 51,125 |
| Accretion Expense | 3,953 | 2,670 | 2,448 |
| Depreciation, Depletion and Amortization ($1.92, $1.98 and $1.72 per Mcfe of production) | 90,239 | 93,927 | 90,205 |
| Impairment of Oil and Gas Producing Properties(2) | — | 104,739 | — |
| Income Tax Expense | 82,631 | 56,117 | 82,687 |
| Results of Operations for Producing Activities (excluding corporate overheads and interest charges) | $134,286 | $102,870 | $146,834 |

(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***

The Company's proved oil and gas reserves are located in the United States. The estimated quantities of proved reserves disclosed in the table below are based upon estimates by qualified Company geologists and engineers and are audited by independent petroleum engineers. Such estimates are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions.

| | Gas MMcf | | | | | |
|---|---|---|---|---|---|---|
| | U. S. | | | | | |
| | Gulf Coast Region | West Coast Region | Appalachian Region | Total U.S. | Canada (Discontinued Operations) | Total Company |
| Proved Developed and Undeveloped Reserves: | | | | | | |
| September 30, 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 |
| Extensions and Discoveries | 3,577 | — | 29,676 | 33,253 | 1,333 | 34,586 |
| Revisions of Previous Estimates | (9,851) | 1,238 | 1,618 | (6,995) | 11,634 | 4,639 |
| Production | (10,356) | (3,929) | (5,555) | (19,840) | (6,426) | (26,266) |
| Sales of Minerals in Place | (36) | — | (34) | (70) | (40,075) | (40,145) |
| September 30, 2007 | 25,136 | 73,175 | 107,078 | 205,389 | — | 205,389 |
| Proved Developed Reserves: | | | | | | |
| 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 |
| September 30, 2007 | 25,136 | 66,017 | 96,674 | 187,827 | — | 187,827 |

| | Oil Mbbl | | | | | |
|---|---|---|---|---|---|---|
| | U.S. | | | | | |
| | Gulf Coast Region | West Coast Region | Appalachian Region | Total U.S. | Canada (Discontinued Operations) | Total Company |
| Proved Developed and Undeveloped Reserves: | | | | | | |
| September 30, 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) |
| September 30, 2005 | 1,295 | 57,085 | 177 | 58,557 | 1,700 | 60,257 |
| Extensions and Discoveries | 39 | 172 | 108 | 319 | 128 | 447 |
| Revisions of Previous Estimates | 595 | (80) | 57 | 572 | 101 | 673 |
| Production | (685) | (2,582) | (69) | (3,336) | (272) | (3,608) |
| Purchases of Minerals in Place | — | 274 | — | 274 | — | 274 |
| Sales of Minerals in Place | — | — | — | — | (25) | (25) |
| September 30, 2006 | 1,244 | 54,869 | 273 | 56,386 | 1,632 | 58,018 |
| Extensions and Discoveries | 63 | — | 281 | 344 | 108 | 452 |
| Revisions of Previous Estimates | 851 | (6,822) | 84 | (5,887) | (76) | (5,963) |
| Production | (717) | (2,403) | (124) | (3,244) | (206) | (3,450) |
| Sales of Minerals in Place | (6) | — | (7) | (13) | (1,458) | (1,471) |
| September 30, 2007 | 1,435 | 45,644 | 507 | 47,586 | — | 47,586 |
| Proved Developed Reserves: | | | | | | |
| 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 |
| September 30, 2007 | 1,435 | 36,509 | 483 | 38,427 | — | 38,427 |

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

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

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| **United States** | | | |
| Future Cash Inflows | $4,879,496 | $3,911,059 | $6,138,522 |
| Less: | | | |
| Future Production Costs | 872,536 | 758,258 | 777,417 |
| Future Development Costs | 229,987 | 205,497 | 188,795 |
| Future Income Tax Expense at Applicable Statutory Rate | 1,423,707 | 1,019,307 | 1,868,548 |
| Future Net Cash Flows | 2,353,266 | 1,927,997 | 3,303,762 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | 1,292,804 | 1,066,338 | 1,812,230 |
| Standardized Measure of Discounted Future Net Cash Flows | 1,060,462 | 861,659 | 1,491,532 |
| **Canada — Discontinued Operations** | | | |
| Future Cash Inflows | — | 197,227 | 601,210 |
| Less: | | | |
| Future Production Costs | — | 92,234 | 136,338 |
| Future Development Costs | — | 11,520 | 12,197 |
| Future Income Tax Expense at Applicable Statutory Rate | — | (151) | 137,524 |
| Future Net Cash Flows | — | 93,624 | 315,151 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | — | 19,375 | 108,508 |
| Standardized Measure of Discounted Future Net Cash Flows | — | 74,249 | 206,643 |
| **Total** | | | |
| Future Cash Inflows | 4,879,496 | 4,108,286 | 6,739,732 |
| Less: | | | |
| Future Production Costs | 872,536 | 850,492 | 913,755 |
| Future Development Costs | 229,987 | 217,017 | 200,992 |
| Future Income Tax Expense at Applicable Statutory Rate | 1,423,707 | 1,019,156 | 2,006,072 |
| Future Net Cash Flows | 2,353,266 | 2,021,621 | 3,618,913 |
| Less: | | | |
| 10% Annual Discount for Estimated Timing of Cash Flows | 1,292,804 | 1,085,713 | 1,920,738 |
| Standardized Measure of Discounted Future Net Cash Flows | $1,060,462 | $ 935,908 | $1,698,175 |

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

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| **United States** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | $ 861,659 | $1,491,532 | $ 935,369 |
| Sales, Net of Production Costs | (276,529) | (306,147) | (272,707) |
| Net Changes in Prices, Net of Production Costs | 539,895 | (941,545) | 1,093,353 |
| Purchases of Minerals in Place | — | 7,607 | — |
| Sales of Minerals in Place | 484 | — | (762) |
| Extensions and Discoveries | 98,751 | 66,975 | 100,102 |
| Changes in Estimated Future Development Costs | (83,199) | (83,750) | (89,805) |
| Previously Estimated Development Costs Incurred | 58,710 | 67,048 | 25,038 |
| Net Change in Income Taxes at Applicable Statutory Rate | (174,920) | 404,176 | (362,956) |
| Revisions of Previous Quantity Estimates | (140,203) | 4,850 | 25,055 |
| Accretion of Discount and Other | 175,814 | 150,913 | 38,845 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | 1,060,462 | 861,659 | 1,491,532 |
| **Canada — Discontinued Operations** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | 74,249 | 206,643 | 110,730 |
| Sales, Net of Production Costs | (34,581) | (54,176) | (49,467) |
| Net Changes in Prices, Net of Production Costs | 35,628 | (180,216) | 174,985 |
| Purchases of Minerals in Place | — | — | — |
| Sales of Minerals in Place | (151,236) | (238) | (3,751) |
| Extensions and Discoveries | 6,908 | 10,369 | 31,028 |
| Changes in Estimated Future Development Costs | 5,722 | (3,282) | (11,007) |
| Previously Estimated Development Costs Incurred | 5,798 | 4,450 | 12,032 |
| Net Change in Income Taxes at Applicable Statutory Rate | (10,075) | 82,966 | (51,541) |
| Revisions of Previous Quantity Estimates | 34,998 | (15,478) | (5,990) |
| Accretion of Discount and Other | 32,589 | 23,211 | (376) |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | — | 74,249 | 206,643 |

| | Year Ended September 30 | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| | | (Thousands) | |
| **Total** | | | |
| Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year | 935,908 | 1,698,175 | 1,046,099 |
| Sales, Net of Production Costs | (311,110) | (360,323) | (322,174) |
| Net Changes in Prices, Net of Production Costs | 575,523 | (1,121,761) | 1,268,338 |
| Purchases of Minerals in Place | — | 7,607 | — |
| Sales of Minerals in Place | (150,752) | (238) | (4,513) |
| Extensions and Discoveries | 105,659 | 77,344 | 131,130 |
| Changes in Estimated Future Development Costs | (77,477) | (87,032) | (100,812) |
| Previously Estimated Development Costs Incurred | 64,508 | 71,498 | 37,070 |
| Net Change in Income Taxes at Applicable Statutory Rate | (184,995) | 487,142 | (414,497) |
| Revisions of Previous Quantity Estimates | (105,205) | (10,628) | 19,065 |
| Accretion of Discount and Other | 208,403 | 174,124 | 38,469 |
| Standardized Measure of Discounted Future Net Cash Flows at End of Year | $1,060,462 | $ 935,908 | $1,698,175 |

## Schedule II — Valuation and Qualifying Accounts

| Description | Balance at Beginning of Period | Additions Charged to Costs and Expenses | Additions Charged to Other Accounts | Deductions(3) | Balance at End of Period |
|---|---|---|---|---|---|
| | | | (Thousands) | | |
| **Year Ended September 30, 2007** | | | | | |
| Allowance for Uncollectible Accounts | $31,427 | $27,652 | $1,414(1) | $31,839 | $28,654 |
| **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 |

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

(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 the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2007.

**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, 2007. 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, 2007.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued a report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2007. 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, 2007 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

### Item 9B *Other Information*

None

## PART III

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

The information required by this item concerning the directors of the Company and corporate governance is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008

Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. 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 2011," "Directors Whose Terms Expire in 2010," "Directors Whose Terms Expire in 2009," and "Section 16(a) Beneficial Ownership Reporting Compliance" and is incorporated herein by reference. The information concerning corporate governance is set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

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

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

## Item 11 *Executive Compensation*

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information concerning executive compensation is set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee," is incorporated herein by reference.

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

### Equity Compensation Plan Information

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. 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 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. 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 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information concerning security ownership of management is set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

### *(c) Changes in Control*

None

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

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. The information regarding certain relationships and related transactions is set forth in the definitive Proxy Statement under the headings "Compensation Committee Interlocks and Insider Participation" and "Related Person Transactions" and is incorporated herein by reference. The information regarding director independence is set forth in the definitive Proxy Statement under the heading "Director Independence" and is incorporated herein by reference.

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

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its 2008 Annual Meeting of Stockholders will be filed with the SEC not later than 120 days after September 30, 2007. 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: |
| • | Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880) |
| • | Certificate of Amendment of Restated Certificate of Incorporation (Exhibit 3(ii), Form 8-K dated March 14, 2005 in File No. 1-3880) |
| 3(ii) | By-Laws: |
| • | National Fuel Gas Company By-Laws as amended June 7, 2007 (Exhibit 3.1, Form 8-K dated June 8, 2007 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) |

| Exhibit Number | Description of Exhibits |
|---|---|
| • | Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992 in File No. 1-3880) |
| • | Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992 in File No. 1-3880) |
| • | Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401) |
| • | Fourteenth Supplemental Indenture, dated as of July 1, 1993,to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993 in File No. 1-3880) |
| • | Fifteenth Supplemental Indenture, dated as of September 1, 1996, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880) |
| • | Indenture dated as of October 1, 1999, between the Company and The Bank of New York (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880) |
| • | Officers Certificate Establishing Medium-Term Notes, dated October 14, 1999 (Exhibit 4.2, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880) |
| • | Officers Certificate establishing 5.25% Notes due 2013, dated February 18, 2003 (Exhibit 4, Form 10-Q for the quarterly period ended March 31, 2003 in File No. 1-3880) |
| 4.1 | Amended and Restated Rights Agreement, dated as of September 1, 2007, between the Company and The Bank of New York |
| 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: |
| 10.1 | Form of Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of Philip C. Ackerman, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith and Ronald J. Tanski |
| 10.2 | Employment Continuation and Noncompetition Agreement, dated as of September 20, 2007, among the Company, Seneca Resources Corporation and Matthew D. Cabell |
| • | Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |
| • | National Fuel Gas Company 1993 Award and Option Plan, dated February 18, 1993 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880) |
| • | Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated October 27, 1995 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880) |
| • | Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 11, 1996 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880) |
| • | Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 18, 1996 (Exhibit 10, Form 10-Q for the quarterly period ended December 31, 1996 in File No. 1-3880) |
| • | National Fuel Gas Company 1993 Award and Option Plan, amended through June 14, 2001 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880) |

| Exhibit Number | Description of Exhibits |
|---|---|

- National Fuel Gas Company 1993 Award and Option Plan, amended through September 8, 2005 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
- Administrative Rules with Respect to At Risk Awards under the 1993 Award and Option Plan (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of February 15, 2007 (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2007 in File No. 1-3880)
- Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005 in File No. 1-3880)
- Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006 in File No. 1-3880)
- Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
- Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
- Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)
- National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2007 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)
- Description of performance goals for certain executive officers under the Company's Annual At Risk Compensation Incentive Program (Exhibit 10.8, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
- Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective December 6, 2006 (Exhibit 10.6, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880)
- National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994 in File No. 1-3880)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3,Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
- Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
- Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1,Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880)
- Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880)
- Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880)

| Exhibit Number | Description of Exhibits |
|---|---|
| • | Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| • | National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997 in File No. 1-3880) |
| • | Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880) |
| • | Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880) |
| • | Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005 in File No. 1-3880) |
| • | National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005 in File No. 1-3880) |
| 10.3 | National Fuel Gas Company Tophat Plan, as amended September 20, 2007 |
| • | 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 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) |

| Exhibit Number | Description of Exhibits |
|---|---|
| • | National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |
| 10.4 | National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007 |
| • | National Fuel Gas Company and Participating Subsidiaries 1996 Executive Retirement Plan Trust Agreement (II), dated May 10, 1996 (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880) |
| • | National Fuel Gas Company Participating Subsidiaries Executive Retirement Plan 2003 Trust Agreement(I), dated September 1, 2003 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880) |
| • | National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 8-K dated June 3, 2005 in File No. 1-3880) |
| • | Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of March 20, 1997 regarding the Retainer Policy for Non-Employee Directors (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880) |
| 10.5 | Amended and Restated Retirement Benefit Agreement for David F. Smith, dated September 20, 2007,among the Company, National Fuel Gas Supply Corporation and David F. Smith |
| • | 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) |
| • | 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 long-term performance incentives under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.7, Form 10-Q for the quarterly period ended December 31, 2006 in File No. 1-3880) |
| • | Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006 in File No. 1-3880) |
| • | Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006 in File No. 1-3880) |
| • | 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, 2003 through 2007 |
| 21 | Subsidiaries of the Registrant |
| 23 | Consents of Experts: |

| Exhibit Number | Description of Exhibits |
|---|---|
| 23.1 | Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation |
| 23.2 | Consent of Independent Registered Public Accounting Firm |
| 31 | Rule 13a-14(a)/15d-14(a) Certifications: |
| 31.1 | Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act |
| 31.2 | Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act |
| 32 | Certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 99 | Additional Exhibits: |
| 99.1 | Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation |
| 99.2 | Company Maps |

• Incorporated herein by reference as indicated.

All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K

•• In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference

## 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: November 29, 2007

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: November 29, 2007 |
| /s/ R. T. Brady<br>R. T. Brady | Director | Date: November 29, 2007 |
| /s/ R. D. Cash<br>R. D. Cash | Director | Date: November 29, 2007 |
| /s/ S. E. Ewing<br>S. E. Ewing | Director | Date: November 29, 2007 |
| /s/ R. E. Kidder<br>R. E. Kidder | Director | Date: November 29, 2007 |
| /s/ C. G. Matthews<br>C. G. Matthews | Director | Date: November 29, 2007 |
| /s/ G. L. Mazanec<br>G. L. Mazanec | Director | Date: November 29, 2007 |
| /s/ R. G. Reiten<br>R. G. Reiten | Director | Date: November 29, 2007 |
| /s/ J. F. Riordan<br>J. F. Riordan | Director | Date: November 29, 2007 |
| /s/ D. F. Smith<br>D. F. Smith | President, Chief Operating Officer and Director | Date: November 29, 2007 |

| Signature | Title | |
|---|---|---|
| /s/ R. J. Tanski<br>R. J. Tanski | Treasurer and Principal Financial Officer | Date: November 29, 2007 |
| /s/ K. M. Camiolo<br>K. M. Camiolo | Controller and Principal Accounting Officer | Date: November 29, 2007 |

## Investor Information

**Common Stock Transfer Agent and Registrar**
The Bank of New York Mellon Company, Inc.
101 Barclay Street
New York, NY 10286
Tel. (800) 648-8166
Website: http://www.stockbny.com
E-mail: shareowners@bankofny.com

**Stock Exchange Listing**
New York Stock Exchange (Stock Symbol: NFG)

The Company's Chief Executive Officer filed with the New York Stock Exchange on March 15, 2007, the certification required by Section 303A.12(a) of the NYSE Listed Company Manual. In addition, the most recent certifications by the Company's Chief Executive Officer and Principal Financial Officer pursuant to Sections 302 and 906 of the Sarbanes-Oxley Act of 2002 were filed as exhibits to the Company's Form 10-K for the fiscal year ended September 30, 2007.

**National Fuel Direct Stock Purchase and Dividend Reinvestment Plan**
National Fuel offers a simple, cost-effective method for purchasing shares of National Fuel stock.

A prospectus, which includes details of the Plan, can be obtained by calling, writing or e-mailing The Bank of New York Mellon Company, Inc., the agent for the Plan, at:

BNY MELLON Shareowner Services*
Church Street Station
P.O. Box 11258
New York, NY 10286-1258
Tel. (800) 648-8166
E-mail: shareowners@bankofny.com

*Change-of-address notices and inquiries about dividends should be sent to the Transfer Agent at the address shown in the first paragraph on this page.

**Trustee for Debentures**
The Bank of New York Mellon Company, Inc.
101 Barclay Street
New York, NY 10286

**Annual Meeting**
Stockholders of record as of the close of business on December 26, 2007, will receive formal notice of the Annual Meeting of Stockholders, a proxy statement and a proxy card.

**Investor Relations**
Investors or financial analysts desiring information should contact:

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**Additional Shareholder Reports**
Additional copies of this report and the Financial and Statistical Supplement to the 2007 Annual Report can be obtained without charge by writing to or calling:

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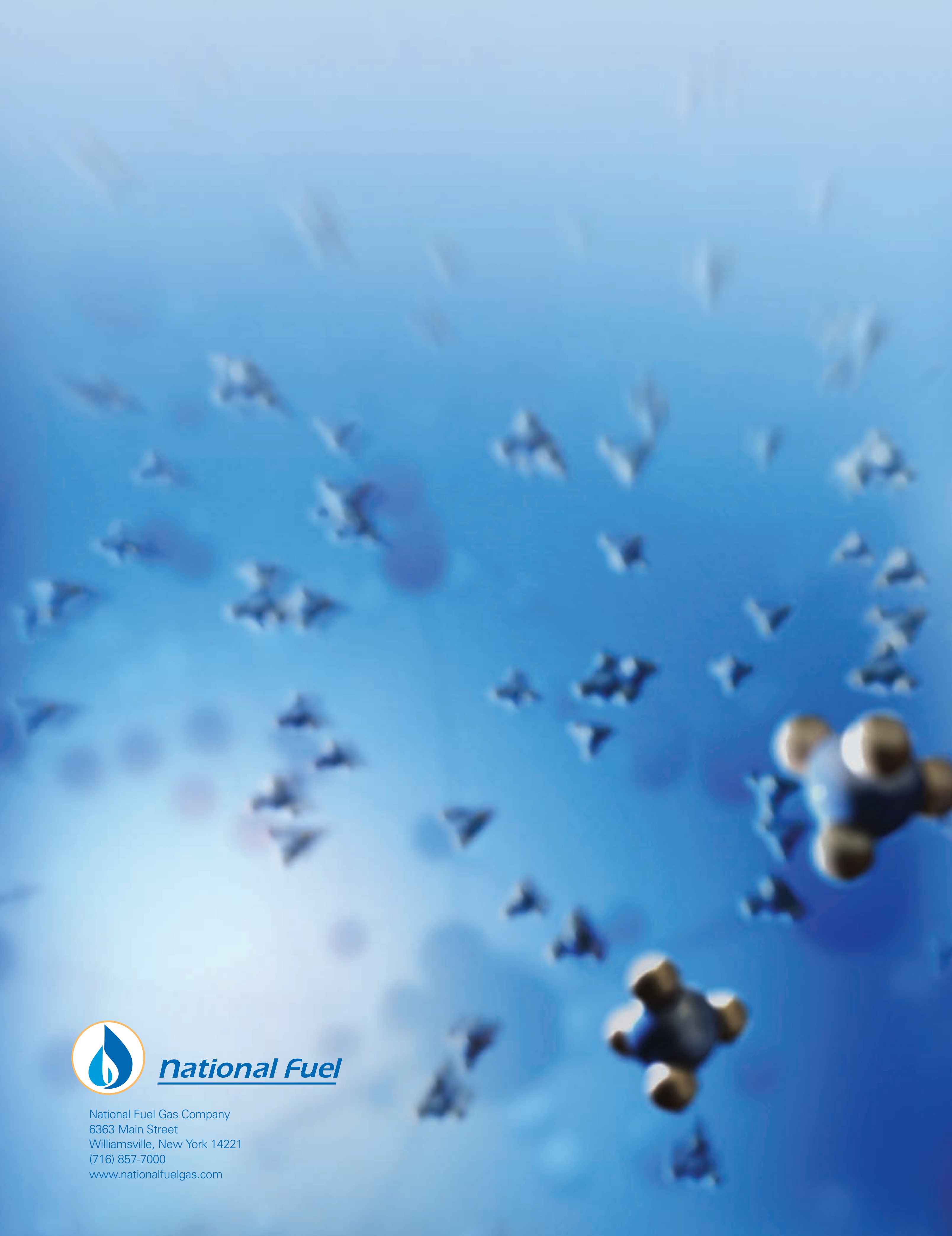

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