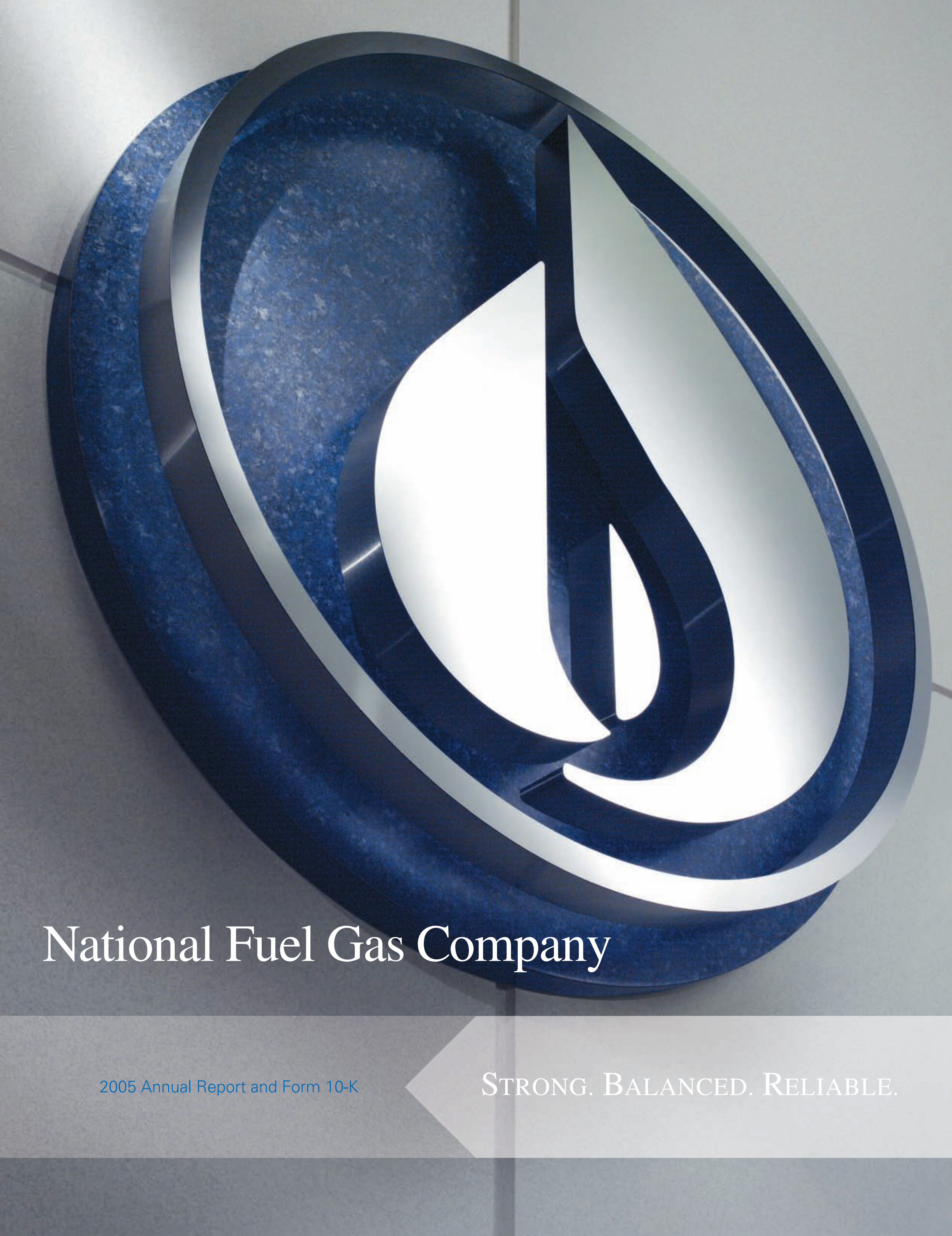

National Fuel Gas Company

2005 Annual Report and Form 10-K

STRONG. BALANCED. RELIABLE.

Strong. Balanced. Reliable.

A company cannot prosper for more than a century by focusing only on today. We have built a healthy, robust organization that performs soundly during times of economic prosperity, yet remains nimble enough to generate results when faced with economic adversity. Our strategic asset base has been built with an eye toward the long-term view rather than one that is shortsighted. This vision has served us well, as has our ability to resist the temptation to become something that we are not. More importantly, we have assembled a team of dedicated, capable employees whose integrity and honesty continue to define our Company, and who remain steadfastly committed to those who depend upon us for their energy needs. We are confident in who we are: a strong, balanced, and reliable energy provider. We are proud of the results we have delivered to both our investors and customers.

Corporate Profile

National Fuel Gas Company, incorporated in 1902, is a diversified energy company with its headquarters in Williamsville, New York. The Company's $3.7 billion in assets is distributed among five principal business segments: Exploration and Production, Pipeline and Storage, Utility, Timber, and Energy Marketing. 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 103-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, the Gulf Coast region of Texas, Louisiana and Alabama, and the western provinces of Canada. Currently, Seneca's exploration emphasis is centered on drilling for new reserves in Canada and the Gulf of Mexico, while development drilling continues to expand in the Appalachian region and in California.

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 2,972 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 731,000 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.

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 from its New York and Pennsylvania land holdings.

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.

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

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Financial Highlights

Year Ended September 30,	**2005**	2004	2003	2002	2001
Operating Revenues *(Thousands)* (1)	**$ 1,923,549**	$ 1,907,968	$ 1,921,573	$ 1,369,869	$ 1,962,874
Net Income Available for Common Stock *(Thousands)*	**$ 189,488** (2)	$ 166,586	$ 178,944 (3)	$ 117,682 (4)	$ 65,499 (5)
Return on Average Common Equity (6)	**15.3%**	13.9%	16.7%	11.7%	6.6%
Per Common Share					
Basic Earnings	**$ 2.27**	$ 2.03	$ 2.21 (7)	$ 1.47	$ 0.83
Diluted Earnings	**$ 2.23**	$ 2.01	$ 2.20 (7)	$ 1.46	$ 0.82
Dividends Paid	**$ 1.13**	$ 1.09	$ 1.05	$ 1.02	$ 0.97
Dividend Rate at Year-End	**$ 1.16**	$ 1.12	$ 1.08	$ 1.04	$ 1.01
Book Value at Year-End	**$ 14.58**	$ 15.11	$ 13.97	$ 12.54	$ 12.63
Common Shares Outstanding at Year-End	**84,356,748**	82,990,340	81,438,290	80,264,734	79,406,105
Weighted Average Common Shares Outstanding					
Basic	**83,541,627**	82,045,535	80,808,794	79,821,430	79,053,444
Diluted	**85,029,131**	82,900,438	81,357,896	80,534,453	80,361,258
Average Common Shares Traded Daily	**322,887**	223,600	221,021	180,675	222,308
Common Stock Price					
High	**$ 36.00**	$ 28.43	$ 27.51	$ 25.70	$ 32.25
Low	**$ 26.20**	$ 21.71	$ 17.95	$ 15.61	$ 21.96
Close	**$ 34.20**	$ 28.33	$ 22.85	$ 19.87	$ 23.03
Net Cash Provided by Operating Activities *(Thousands)*	**$ 317,346**	$ 437,149	$ 325,728	$ 345,550	$ 414,027
Total Assets *(Thousands)*	**$ 3,722,652**	$ 3,717,603	$ 3,725,414	$ 3,429,163	$ 3,452,566
Capital Expenditures *(Thousands)*	**$ 219,530**	$ 172,341	$ 152,251	$ 232,368	$ 292,706
Investment in Subsidiaries, Net of Cash Acquired *(Thousands)*	**$ –**	$ –	$ 228,814	$ –	$ 90,567
Volume Information					
Utility Throughput-MMcf					
Gas Sales	**80,274**	101,961	112,162	101,444	104,186
Gas Transportation	**59,770**	60,565	64,232	61,909	66,283
Pipeline & Storage Throughput-MMcf					
Gas Transportation	**372,379**	351,683	350,929	297,822	321,555
Production Volumes					
Gas-MMcf	**29,179**	33,013	33,805	41,454	41,004
Oil-Mbbl	**3,869**	4,528	6,737	7,662	7,857
Total-MMcfe	**52,393**	60,181	74,227	87,426	88,146
Proved Reserves					
Gas-MMcf	**238,140**	224,784	251,117	258,221	322,380
Oil-Mbbl	**60,257**	65,213	69,764	99,717	115,328
Total-MMcfe	**599,682**	616,062	669,700	856,523	1,014,348
Energy Marketing Volumes-MMcf					
Gas	**40,683**	41,651	45,135	33,042	36,753
Average Number of Utility Retail Customers	**674,633**	678,976	680,007	680,489	678,357
Average Number of Utility Transportation Customers	**56,262**	53,331	53,381	51,729	54,140
Number of Employees at September 30 (8)	**2,044**	2,918	3,037	3,177	3,235

(1) Excludes discontinued operations.
(2) Includes gain on sale of United Energy of $25.8 million.
(3) 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.
(4) Includes impairment of investment in a partnership of ($9.9) million.
(5) Includes impairment of oil and gas producing properties of ($104.0) million.
(6) Calculated using average Total Comprehensive Shareholders' 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 26, 863, 897, 944 and 991 international employees at September 30, 2005, 2004, 2003, 2002 and 2001, respectively.

National Fuel at a Glance

Exploration and Production

2005 Highlights

- Net income of $50.7 million contributed 33% of the Company's income from continuing operations.
- Achieved targeted production of 52.4 Bcfe, 56% natural gas, 44% oil.
- Drilled 241 new wells with a 98% success rate.
- Weighted average prices of natural gas and oil after hedging rose from $5.06 to $6.23 per Mcf and from $26.40 to $27.86 per barrel, respectively, offsetting a decrease in total production of 13%.

Pipeline and Storage

2005 Highlights

- Net income of $60.5 million contributed more than 39% of the Company's income from continuing operations.
- Realized a $2.6 million gain after the sale of 680 MDth of base gas from our jointly owned Ellisburg Storage Field, opening space for additional ongoing storage service.
- Filed an application with the Federal Energy Regulatory Commission (FERC) to build the proposed Empire Connector Project.

Utility

2005 Highlights

- Net income of $39.2 million, while providing more than 25% of the Company's income from continuing operations, was down $7.5 million from fiscal 2004.
- Settled rate cases in both our New York and Pennsylvania divisions, for a combined $33 million base rate increase.
- New York rate case was the first filing since 1995.

Timber

2005 Highlights

- Net income of $5.0 million.
- Production increased by 6.9% to 33.6 million board feet, up from 31.4 million last year.
- Added two new kilns, increasing the amount of green lumber that can be dried.

Energy Marketing

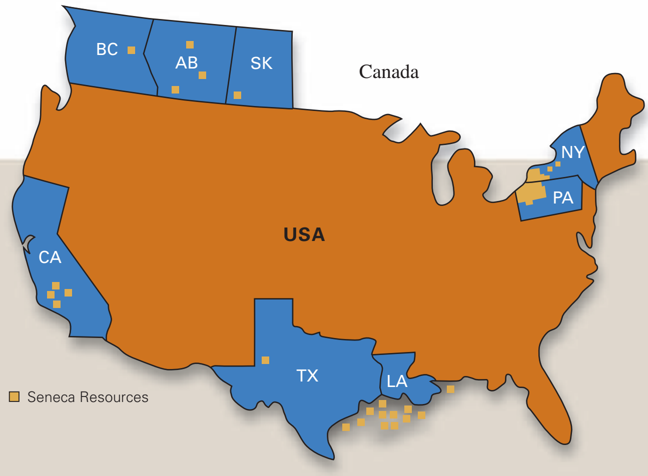
2005 Highlights

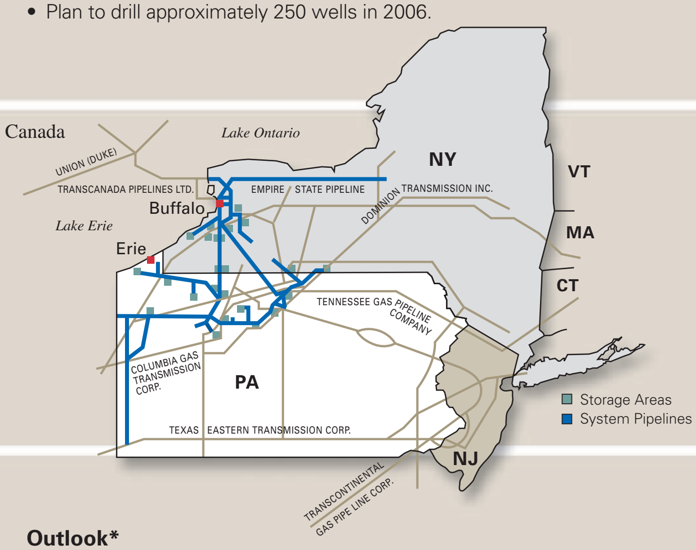
- Net income of $5.1 million.
- Retained its position as the largest marketer on National Fuel's utility system.
- Continued expansion to the east, with considerable progress in the Rochester and Syracuse markets.

The net income figures above, together with a loss of $6.9 million for Corporate and All Other, total to $153.5 million, our net income from continuing operations. Including net income of $36.0 million from discontinued operations, consolidated Company net income totals $189.5 million.

Outlook*

- Production goal of 46-51 Bcf equivalent annually to emphasize natural gas drilling and production.
- Capital budget of $155 million, with plans to focus on areas of proven success, living within cash flow, and controlling production costs.
- Plan to drill approximately 250 wells in 2006.



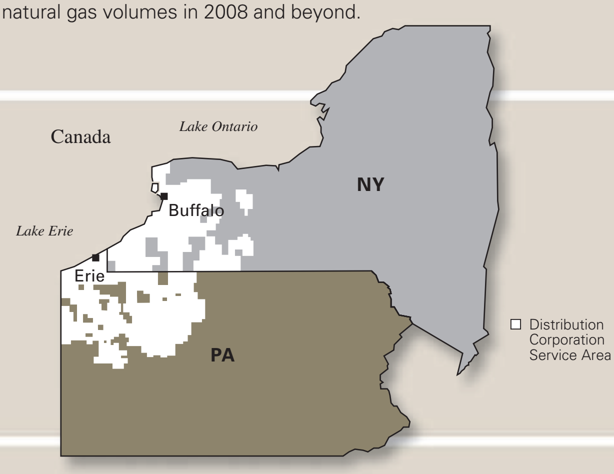


Outlook*

- Strategic value from acquisition of Empire State Pipeline is emerging with proposed Empire Connector project.
- Considering small pipeline connector from western terminus of the proposed Empire Connector-Millennium Pipeline to our existing Tuscarora Storage facilities, to provide delivery and take-away capacity of natural gas volumes in 2008 and beyond.

Outlook*

- Help customers to better understand the marketplace issues that drive high prices and find ways for them to manage their heating costs.
- Maintain excellent levels of operational safety and customer service throughout our service territories while continuing to contain costs.

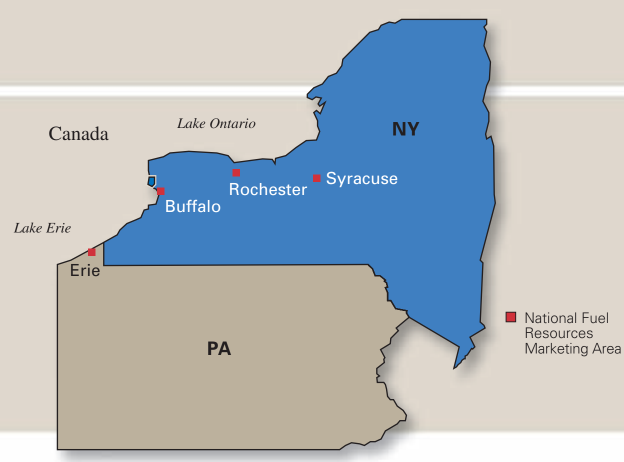


Outlook*

- Earnings and production expected to remain near 2005 levels.
- Remain committed to responsible stewardship of this resource.

Outlook*

- Continue to focus on core markets.
- Provide energy expertise to commercial and individual customers throughout western and central New York and northwestern Pennsylvania.



Note: This document contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements, including those designated by an asterisk (""), should be read with cautionary statements and important factors included at Item 7 of the Company's Form 10-K, under the heading, "Safe Harbor for Forward-Looking Statements."*

To Our Shareholders

The record-high earnings which your Company achieved in fiscal 2005 confirm the benefits of our strategy to participate in all segments of the natural gas business, from the bottom of the well to the burner tip. The $2.23 per share of earnings in fiscal 2005 marks the third year in a row that National Fuel's earnings have exceeded $2.00 per share. In each of the last three years, a different segment of your Company took advantage of opportunities to contribute strong earnings and put us "over the top" each year. In fiscal 2003, the Timber segment provided a large gain that allowed us to acquire the Empire State Pipeline without increasing the leverage of the Company. In fiscal 2004, strong earnings and cash flow provided by the Exploration and Production segment allowed us to pay down additional debt. And, in fiscal 2005, strong performance in the Pipeline and Storage segment, combined with a large gain in our former International segment, allowed us to achieve this new record.

I am also pleased to report that, for the 35th consecutive year, your Board of Directors has increased the annual dividend rate. The current rate is $1.16 per share, up 3.6% from last year's rate of $1.12 per share. Since its inception in 1902, National Fuel has paid a dividend every year. The Company's long dividend history, and its dividend increases over the past 35 years, make it a member of an increasingly elite group of publicly traded companies. According to a recent *Business Week* article, out of more than 6,000 listed U.S. stocks, only 85 have increased dividends for at least 25 straight years.[1] Strong earnings and free cash flow allowed us to pay down debt, raising the equity component of our capitalization to over 52%. Our commercial paper program and credit facilities, which were untapped at fiscal year-end, allow us to borrow up to $580 million and provide substantial liquidity for our future working capital needs and investment opportunities. In addition, the market price of your stock closed at $34.20 per share on September 30, an increase of nearly 21% from last year's record fiscal year-end close of $28.33 per share.

In short, your Company is financially stronger than ever. We believe, however, that the market has not yet fully recognized the value of our strong cash flow position, oil and gas reserves, and improved balance sheet. To help correct this disparity, we will be emphasizing our investor relations program to ensure the market is well informed of our strengths.*

Chairman, President and Chief Executive Officer Philip C. Ackerman at corporate headquarters in Williamsville, New York

[1] *Robert Barker, "Low Profiles, High Yields," Business Week, December 12, 2005, p. 28.*

Based on our strong cash flow position, at its December 2005 meeting, the Board of Directors voted to repurchase up to 8 million shares of the Company's stock. We believe that, at the present time, it is more attractive to buy assets in the form of company stock than it is to chase after other scarce assets on the open market. Of course, the simple mathematics of reducing the number of shares outstanding will increase earnings per share, as well.* As most of our investors are all too well aware, the interest rates available for short-term cash investment are not attractive, which makes the purchase of our own stock an even better alternative for our cash.

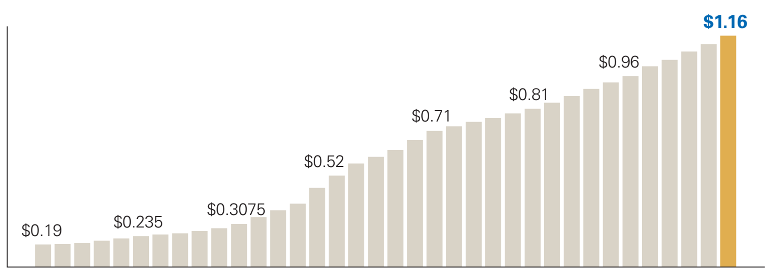
For many years, I have spoken of our commitment to participate in all aspects of the natural gas business. This strategy continues to provide a three-fold benefit to your Company. First, we have the financial strength to buy and build the real assets needed to generate future earnings. Our exploration and development program, for instance, is fully funded by the cash flow from that segment. Second, the balance we achieve by participating in all aspects of the natural gas value chain mitigates the risk we may otherwise experience from the fluctuations of economic cycles in each of our business units. An example in this regard is that, as energy prices fall, utility operations generally prosper. Finally, our financial strength and diversification together augment our reliability, not only to provide the resources that safely and efficiently deliver the natural gas that keeps homes warm and businesses operating, but also to generate a continuous stream of earnings that furnish a dividend to our shareholders.

This year, a number of activities contributed to our successful financial performance. We took advantage of the favorable tax provisions of the American Jobs Creation Act of 2004, which allowed us to repatriate $72.8 million in dividends from unremitted earnings in our Czech operations at a tax rate of 5.25% rather than the standard 35% corporate tax rate. Even though the taxes we paid at the reduced rate decreased the Company's earnings by $3.8 million, our ability to invest this cash in our domestic operations has given us much more financial flexibility.

In June, we received regulatory approval to sell 680 thousand dekatherms (MDth) of base gas from our jointly owned Ellisburg Storage Field, thus expanding our future top-gas storage capabilities. We recognized a net gain of $2.6 million from this sale. During July, we completed the sale of our Czech Republic assets (which were worrisome for some investors), realizing a net gain of $25.8 million. During the year, we settled rate cases in both of our Utility divisions, increasing base rates by a combined $33 million annually, while providing a two-year, $15 million annual bill reduction to our New York customers. The full impact of these rate settlements will not be realized until fiscal 2006.

Furthermore, at September 30, we nearly doubled the reserve for bad debt in our Utility segment from $12.9 million to $25.1 million. This action was taken because we experienced a 10% increase in aged receivables, and we expect the unprecedented high commodity price environment to continue throughout the upcoming heating season.* Lastly, we recorded impairments of two minor generating assets totaling approximately $4.5 million.

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



For the second year in a row, we met our oil and gas production goals with 52.4 Bcfe total production. While this was 13% lower than last year's production, the decline was anticipated as we continue our plans to move away from offshore production and concentrate development in onshore producing areas. Hurricane Katrina minimally affected our offshore Gulf of Mexico operations, but Hurricane Rita had a more considerable impact, affecting nearly all Gulf Coast production, not just ours. We safely shut in operations in both instances, and suffered major damage to only one platform during Hurricane Rita. We expect that most of the cost of repairing that damage will be covered by insurance.* However, third-party Gulf pipeline and processing operations were acutely impaired, and this has delayed our ability to get some of our early fiscal 2006 production to market. We were required to recognize a $3.3 million mark-to-market adjustment for the losses on hedges associated with that delayed production. As of the end of November, approximately two-thirds of our Gulf of Mexico production was back on line, and we hope to return to full production by early calendar 2006.*

Fiscal 2005 Performance Highlights

Produced record earnings of $2.23 per share, an 11% increase from fiscal 2004.

Increased annual dividend for the 35th consecutive year.

Achieved forecasted oil and gas production goals, despite Gulf Coast weather catastrophes.

Realized a net gain of $26 million from the sale of our Czech Republic assets.

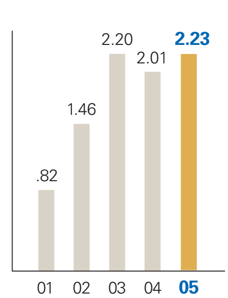
Reduced debt, raising our equity component to more than 52% of total capitalization.

Closing share price of $34.20 at 9/30/05 was nearly 21% above last year's close.

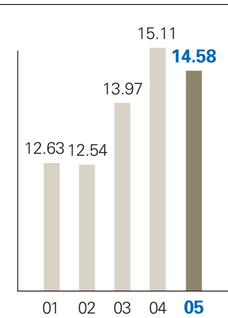
The current strength of our balance sheet, partially built with the proceeds received from the Czech asset sale, as well as the cash generated through our exploration and production operations, affords us great flexibility as we survey the opportunities available to increase the earnings of the Company and sustain a growing dividend to shareholders. We would prefer to increase the earnings power of the Company through the acquisition of assets that would produce additional earnings. However, we will not hastily buy assets or reserves, or act as if our available cash is "burning a hole in our pocket." Historically, we have been successful in taking advantage of the benefits of our diverse base of assets by carefully choosing the appropriate times to make incremental investments in the various subsidiaries. Not only must there be a "fit" within our overall corporate structure, but, more importantly, we must consider whether the expansion will provide a long-term benefit to our shareholders. By operating in the full value chain of the energy business, we have more readily available areas from which to select timely opportunities. For example, in the 1970s, we focused our efforts in the Utility business; during the 1980s, we had growth in the Pipeline and Storage business; and in the 1990s, we seized opportunities to expand the Exploration and Production segment, and entered into the Energy Marketing arena.

As we look ahead, we expect that our near-term growth will come within the Pipeline and Storage segment, with the first stage being provided by our proposed Empire Connector project.* This 78-mile, 24-inch-diameter pipeline, which will be owned 100% by National Fuel, is expected to cost approximately $143 million, and is designed to deliver 250 MDth of natural gas per day.* It will connect our existing Empire State Pipeline from a point near Rochester, New York, to the proposed Millennium Pipeline near Corning, New York.* In October, we filed a formal application with the Federal Energy Regulatory Commission (FERC) for its approval to build the pipeline. We expect to fund this expansion project from available cash.*

Diluted Earnings Per Share *($)*



Book Value Per Common Share *($)*



The Tuscarora extension is a smaller pipeline project, and one for which we have yet to file an application with the FERC for its approval. We expect that the completion of the Empire Connector and Tuscarora pipeline projects will then pave the way for new natural gas storage projects.* These Empire Connector projects, and others like them, will provide an additional layer of recurring, regulated earnings, further enhancing the strength, balance and ability of your Company to continue to develop resources, deliver energy and serve our customers in years to come.*

This past year, the issues regarding high commodity prices have had a disquieting effect on every member of our society. For a number of years, I have discussed the need for a comprehensive national energy policy to address the impending energy supply issue. Oil and natural gas prices were at historic highs prior to the arrival of Hurricanes Katrina and Rita; the resulting devastation from these storms to the energy industry's infrastructure in the Gulf of Mexico only exacerbated an already precarious situation. Although the Energy Policy Act of 2005 was passed this year, it is not a solution that will provide a secure source of reasonably priced energy for the foreseeable future. This country cannot conserve its way to prosperity. We cannot await the discovery of some miraculous technology. The development of more domestic energy supplies is the most economical and quickest solution, and until access to areas for drilling is adequately addressed, there will be more prolonged periods wherein consumers at all levels must deal with burdensome energy prices.

In other business, changes at the Board and management levels have taken place this past year. At the Annual Shareholder Meeting, Craig G. Matthews was elected to serve on your Board. Mr. Matthews brings nearly 40 years of energy industry experience to our Company, most recently as the former Chief Executive Officer of NUI Corporation and the former Vice Chairman and Chief Operating Officer of KeySpan Corporation. Paula M. Ciprich was elected General Counsel to National Fuel Gas Company, and Donna L. DeCarolis was elected President of National Fuel Resources, Inc., our Energy Marketing segment. National Fuel Gas Distribution Corporation elected both Jay W. Lesch and Bruce D. Heine Vice Presidents. In addition, Bruce H. Hale retired from the Company after a 34-year career, which was crowned by the profitable sale of the International assets which were his responsibility.

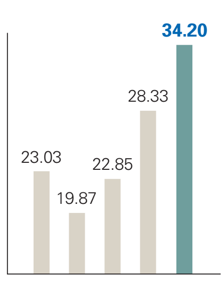
Every era brings its unique challenges, but managing these challenges successfully always depends foremost on the dependability, honesty, and fair dealing that our employees bring to our customers, vendors and each other. These attributes have helped us flourish for more than 100 years, and have brought strength, balance and reliability to all the companies comprising National Fuel. Our success would not be possible without these qualities, or the hard work and dedication of the current work force, as well as those who came before us; we thank them all for these efforts.

The opportunities before us are exciting and we remain committed to being conscientious stewards of the assets you have entrusted to us. In the following pages, you will see and read about many of the operational highlights and initiatives within our major segments, to allow you to better understand these businesses and the great potential we see within each.

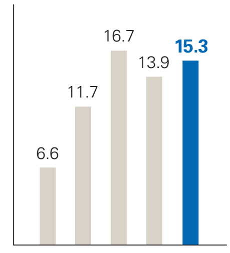
Philip C. Ackerman

Chairman of the Board, President and Chief Executive Officer

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



Return on Average Common Equity *(%)*



STRONG

We have assembled a skilled management team that, with an unwavering commitment to participate in all aspects of the natural gas industry, has generated consistent earnings and a financially robust organization.

The merits of our long-standing strategy of diversifying our exploration and production efforts throughout North America were underscored by the hurricanes of 2005. We have increased our focus on the Appalachian region in recent years, with 80 new wells drilled in fiscal 2005 (using bits like this, capable of penetrating layers of rock deep within the earth). Approximately 120 more wells are planned for Appalachia in fiscal 2006.

We have built a company that withstands market fluctuations and generates long-term results.

Exploration and Production

This year, our Exploration and Production segment contributed 33% of our income from continuing operations and 40% of our cash flow. This segment's earnings of $50.7 million were $3.6 million, or about 7%, less than last year's versus a 13% decline in production that was anticipated. Cash flow from operations was $4.3 million more than capital spending of $122 million in 2005. For fiscal 2006, the capital spending budget was increased to $155 million, due to higher drilling costs and additional drilling prospects which have been identified as a result of the sustained high commodity price environment.

In light of current high commodity prices, we are experiencing an era of renewed activity in the shallow waters of the Gulf of Mexico. The successful wells drilled in the Gulf this past year will be significant contributors to our future production.* Depending on rig, platform and manpower availability, we plan to drill seven to 10 wells in the offshore Gulf of Mexico.* While all producers are experiencing delays in the Gulf region, our participation in the oil and gas production arena remains a logical diversification. With nearly 600 Bcfe of oil and gas reserves, these assets provide significant balance to our Company as a natural hedge against the effects of commodity prices on our utility segment.

Operations in both California and Appalachia are essentially the "bread and butter" of our Exploration and Production segment. Both regions offer long-lived producing reserves through heavy oil in California and natural gas in Appalachia. Our California capital expenditures are primarily for development drilling to accelerate production of existing reserves, while in the East, our drilling is designed to add reserves. In the Appalachian region, we control more than 900,000 acres, and hold nearly two-thirds of the gas rights in fee ownership. We are engaged in an active drilling program in each region, with plans in 2006 to add about 120 wells in Appalachia and 75 wells in California; about $20 million will be spent on drilling in each region.*

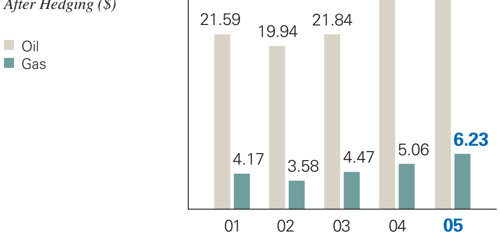
Production cost containment is a priority for us throughout all of our operating regions. In late calendar 2005, we expect to have a new scrubber in full operation in our Midway-Sunset field near Bakersfield, California.* This equipment reduces the need to purchase natural gas for steaming operations by using the oil wells' associated gas to generate the steam needed in the oil production process. With natural gas prices expected to remain near current levels for the foreseeable future, we should realize significant operational savings.*

We continue to drill in the provinces of Alberta, Saskatchewan and British Columbia in Canada. New well drilling in Alberta was delayed this summer because of a

A crew working for Seneca Resources prepares to complete a well near Marienville, Pa., an area in which oil and natural gas production is being developed. In early fiscal 2006, this region became the location of a third-party gas processing plant that, through compression, processes gas from nearby wells.

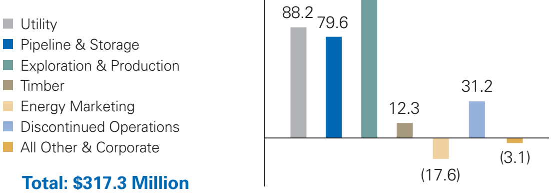
Oil and Gas Prices

Weighted Average After Hedging ($)



Cash Provided By (Used in) Operations, 2005

($ in Millions, By Segment)



Total: $317.3 Million

BALANCED

Our corporate structure is designed to generate balanced performance and steady shareholder returns.

The hurricanes in the Gulf of Mexico this summer caused much of that region's natural gas production to be interrupted. Throughout the U.S., alternate sources of supply were needed, and natural gas from Canada became a popular and logical choice. Since that time, the Supply Corporation's strategically located Concord (N.Y.) Compressor Station has taken on a much larger role, with average daily volumes rising 48% to about 335 MMcf.

This approach allows us to remain strong, even in this time of wild market fluctuations throughout the energy industry.

lengthy rainy season, creating conditions that were too wet to move the rigs and safely drill. We still plan an extensive 45-well drilling program for natural gas in these regions for 2006.*

The bulk of our capital spending in Canada was primarily related to the Monkman region, located in eastern British Columbia. Talisman Energy Inc., our joint venture operator, continues to drill within the more than 200,000 acres encompassing our area of mutual interest (AMI). We participated in the drilling of four wells and the completion of three, having a 20% working interest in each. The first completed well, known as b-79-J and drilled in 2002, currently produces nearly two MMcf per day. The second well, last year's successful b-60-E, was completed in late calendar 2004 and currently produces up to 60 MMcf per day. We are presently awaiting the results of the third completed well, b-75-E, located in the southeastern end of the AMI. Talisman is currently drilling the fifth and sixth wells, named b-93-D and b-77-D, respectively. We also have a 20% working interest in these new wells. The b-93-D well is located approximately five miles southeast of the b-60-E well. The b-77-D well is located near the southeastern-most region of our AMI. Both of these wells will help us to assess the extent of the productive acreage within our AMI.

Because these wells have an average depth of 15,000 to 17,000 feet, drilling takes months to complete. However, given the historic success in the region, and the fact that western Canada is less explored than the lower 48 states, we remain optimistic that this region's potential can contribute significantly to North America's natural gas supply.*

*Mining activities below a six-mile section of Line N, a pipeline located outside of Pittsburgh, Pa., have caused the land around the existing pipe to sink as much as four feet, potentially compromising the pipeline's structural integrity. To ensure Line N's future safety and reliability, a new pipeline will be constructed parallel to the 57-year-old line.**

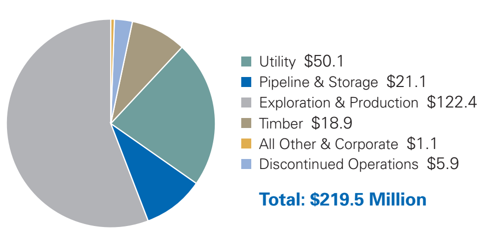
At today's commodity prices, 2006 should be a banner year for this segment.* At the end of November, 69% of our Gulf of Mexico production had been resumed, while the remaining portion continues to be shut-in due to problems caused by the hurricanes. While no dates have been given as to when Gulf pipelines and processing plants will be completely on line, it is generally anticipated that this will occur by the spring of 2006.* Our 2006 production goal is 46 to 51 Bcfe, and our plans to drill nearly 250 wells will keep our staff busy.* Our focus remains on increasing production, containing expenditures, and reducing the inherent risks within oil and natural gas exploration.

Pipeline and Storage

Our Pipeline and Storage segment's earnings for 2005 of $60.5 million increased $12.8 million from 2004 earnings. The sale of 680 MDth of base gas from our portion of the jointly owned Ellisburg Storage Field resulted in a $2.6 million gain and opened this space for additional ongoing storage service, which is already under contract for nearly $1.0 million a year with almost no increase in operating expenses for that service.

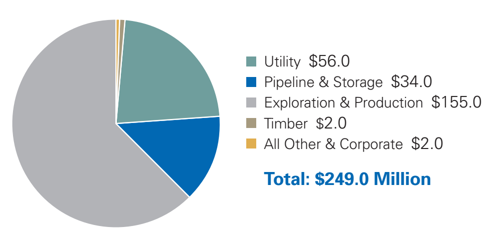
Capital Expenditures, 2005

(By Segment, in Millions)



Capital Expenditures, 2006 Estimated*

(By Segment, in Millions)



Our employees are working tirelessly to help our customers manage their heating bills and find sources of assistance for those in need. We remain steadfast in advocating for a comprehensive national energy policy to address the ever-pressing natural gas supply issue that has created an environment of continued record-high prices.

RELIABLE

National Fuel Gas Company has provided investors with dividend income for 103 consecutive years, including dividend increases during each of the last 35 years.

Capital spending of $21 million was used primarily for improvements and additions to pipeline transmission equipment and gas storage systems.

In the wakes of Hurricanes Katrina and Rita, our transportation volumes increased by nearly three Bcf as various pipeline transmission companies sought alternate routes through our system to deliver natural gas to East Coast markets from sources other than the Gulf of Mexico. Our strategic location played a significant role in bringing Canadian gas to those markets. Also contributing to this year's increased earnings was the $3.9 million gain realized from the resolution of a contingency related to insurance proceeds we previously received regarding lost storage gas.

We are beginning to shift the emphasis of our capital spending from Exploration and Production to Pipeline and Storage. This past year, we have taken several steps to expand our pipeline and storage facilities to move gas from the Niagara River (in western New York) to East Coast markets. After a series of successful meetings with landowners and other interested parties, we filed an application with the FERC to build the Empire Connector. This proposed 78-mile, 24-inch-diameter pipeline, with a targeted in-service date of November 2007, is designed to deliver 250 MDth per day to the proposed Millennium Pipeline, which is designed to serve the New York City area.* Earlier this year, we announced the signing of a Precedent Agreement with KeySpan Gas East Corporation, the anchor tenant, for 150 MDth per day of natural gas, which equals 60% of the Empire Connector's capacity.

The Erie Seawolves (AA baseball) turned to National Fuel's Utility segment to help raise attendance at cold-weather games. The solution came in the form of "Heat Zones," radiant tube, high-intensity infrared heaters, that have helped increase attendance 17 percent in the season's two coldest months (April and May). As a result, two additional heaters will be installed in early 2006.

A smaller, but strategically related, pipeline project is currently under consideration. We are making plans to build a short pipeline connector from the western terminus of the proposed Millennium Pipeline to our existing Tuscarora Storage facilities. The development of this project, with an initial capacity of 130 MDth per day, consists of 23 miles of 24-inch pipe at a cost of approximately $38 million and is contingent upon market demand. Its estimated in-service date is late calendar 2007 or early calendar 2008.* This pipeline would connect the proposed Millennium project to the very heart of our Pennsylvania storage fields, as well as to the Leidy Hub, and also provide deliveries to Millennium and our existing Empire State Pipeline via the Empire Connector.* Millennium will provide the takeaway capacity to move significant natural gas volumes to the East Coast markets.*

In addition, liquefied natural gas (LNG) facilities are expected to play an increasingly important role in our country's natural gas supply equation and could be strategically important to us.* The Cove Point, Maryland, LNG facility is expanding its processing capabilities significantly, and other companies are proposing to construct a pipeline with capacity of 750 MMcf per day to deliver supplies from Cove Point to the Leidy Hub in northern Pennsylvania. From there, additional transportation and/or storage services offered by National Fuel are a logical and economical solution. Future storage conversion and expansion could also depend on the quality of storage required (i.e., large capacity with low deliverability versus small capacity with high deliverability) as well as the proximity to market. National Fuel presently has the ability to provide both, and as the need develops, we'll examine these options at the appropriate time.

One of the most important demonstrations of reliability is our Utility customers' knowledge that we have – for more than 100 years – provided the gas supplies they need, even during the harshest conditions.

Distributed Generation (DG) technology offered the Seneca Nation of Indians an opportunity to lower its energy costs and reduce its dependence on a less reliable electrical grid. Construction of a six-megawatt DG facility for its 113,000 square-foot casino and new 700,000 square-foot luxury hotel in Niagara Falls, N.Y., allowed the Seneca Nation to utilize a cheaper and more reliable energy source. The project increased our Utility segment's throughput by 560,000 Mcf. Pictured with Barry E. Snyder, Seneca Nation President and Board Chairman of the Seneca Gaming Corp. (right), is David Burke of our Energy Services Department.

The Tom Ridge Environmental Center at Presque Isle, set to open to the public in 2006, recently earned the prestigious Leadership in Energy & Environmental Design (LEED) accreditation from the U.S. Green Building Council, thanks in part to the high-efficiency natural gas boiler system chosen for this state-of-the-art, 60,000 square-foot facility. It is the first structure in Erie, Pa., to receive LEED certification.

Our Pipeline and Storage segment has consistently provided a significant portion of our net income and it is exciting to have these expansion prospects in this area of proven performance.

Utility

Earnings in the Utility segment were $39.2 million, a 16% decrease from last year's earnings of $46.7 million. We were successful in containing our costs for many years, but rising medical, prescription drug, and uncollectible expenses, among others, combined with declining usage, required us to file for rate relief in both our New York and Pennsylvania jurisdictions.

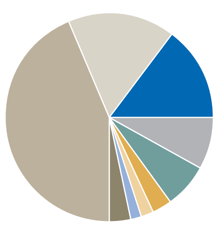
In Pennsylvania, the early settlement of a rate proceeding provided an annual base rate increase of $12 million, effective April 15, 2005. The two-year settlement of our New York rate proceeding was a creative solution from which we feel all parties benefited. The Utility received approval for a $15.2 million increase in its base rates, and $5.8 million of bill credits established under prior rate plans were eliminated. Those changes, together with other minor adjustments, produced a revenue increase of $21.0 million. Under the terms of the New York settlement, however, customers' bills will actually decrease by $15 million annually due to the effect of a change in utility tax laws and a refund of prior tax collections.

This past year, the Utility invested $50 million for upgrades and improvements to its extensive pipeline system. This is one of the most significant ways we can demonstrate our commitment to safely and reliably deliver natural gas to our 731,000 customers. Further, we continue to exceed the customer service standards established by the New York regulators. Although we do not operate under a set of incentive standards in our Pennsylvania jurisdiction, we have voluntarily extended these standards to our customers there. This way, we provide all of our customers with consistent, exceptional service throughout our Utility system.

In addition to this enhanced customer support, and in response to the extraordinary run-up in natural gas prices, our employees are working tirelessly to help our customers manage their heating bills this winter, which promises to be a difficult heating season for customers and employees alike. Late in the summer, we launched a comprehensive communications plan that dedicates significant resources to help customers understand the marketplace issues that are driving high commodity prices, prepare for the heating season and become aware of the resources available to those who may have trouble paying their bills. Currently, approximately 29% of residential customers are on our balanced billing program, and this number is expected to increase significantly as we progress through the heating season.* Our customer service representatives stand ready to offer guidance and assistance to those who are having trouble paying their bills this year, while working diligently to respond to what is sure to be a tremendous influx of inquiries.

The Revenue Dollar 2005 *(In Cents)*

Where it came from:

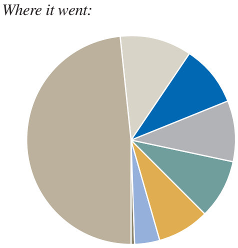


Residential Gas Sales	43.8
Energy Marketing Revenues	16.7
Oil and Gas Production Revenues	14.6
Commercial and Industrial Gas Sales	8.1
Gas Tranportation Revenues	7.0
Timber and Sawmill Revenues	3.1
Discontinued Operations	1.8
Gas Storage Service Revenues	1.7
Other Revenues	3.2

Total: 100.0¢

The Revenue Dollar 2005 *(In Cents)*

Where it went:



Gas Purchased	48.5
Wages, Including Benefits	11.0
Earnings	9.6
Other Materials and Services	9.4
Depreciation	9.1
Taxes	8.1
Interest	4.1
Impairment of Investment in Partnership	0.2

Total: 100.0¢

It is expected that customers will respond to the pressures of high commodity prices by taking additional conservation measures.* This action, one that is anticipated by utilities across the nation, means that we must pursue regulations that neutralize the earnings consequences of conservation measures, while retaining the benefits to customers arising from those efforts. This will mean a departure from the traditional model of rate regulation that is in place in both New York and Pennsylvania, but it is a departure that is advocated by both natural gas utilities and environmental organizations. We expect to pursue these regulatory changes in order to preserve the strength of the Utility segment.*

Cherry, maple and oak trees are among the high-quality timber produced from our asset base of approximately 100,000 acres. The inventory of 386 million board feet increased by 18 percent in 2005. Highland processes its timber at two sawmills in northwestern Pennsylvania and sells the product throughout North America, Europe and Asia.

Timber

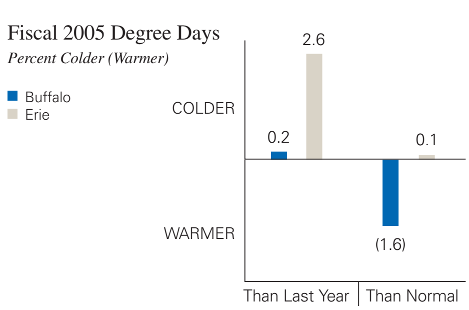
Our timber business helps us further diversify our revenues, adding another layer of protection against potential earnings volatility. Operating from land owned in Pennsylvania and New York, this segment owns two sawmills in northwest Pennsylvania and processes timber consisting primarily of high-quality hardwoods.

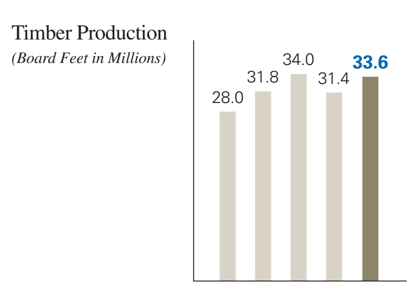
Earnings for this segment of $5.0 million were slightly less than last year's earnings of $5.6 million. The main reason for the decrease is a change in this year's mix of harvested trees to those with a cost basis higher than last year's. With standing timber of about 386 million board feet, the Timber segment remains a strong and important business for our Company. As a real, tangible asset that has the added benefit of biological growth, timber is increasingly viewed by pension funds and other investors as an attractive asset.

Our Timber segment owns and operates two sawmills in northwestern Pennsylvania. Recent capital investments in these facilities have increased efficiency, not only in their overall operation, but also in their ability to capture and use the waste materials created by the milling process. By-products such as tree bark, wood chips, and even sawdust are sold to and used by a wide variety of local industries.

We added two new kilns in early 2005, increasing the amount of green lumber we can dry. We also took advantage of an acquisition opportunity during the year, investing approximately $18 million to acquire 12,300 acres of land and timber in Elk County, Pennsylvania. We remain active in seeking and evaluating other opportunities for this segment.

As we do in all of our businesses, we continually investigate ways we can be as efficient as possible in our operations. Our timber processing facilities are becoming increasingly automated, providing greater speed and less waste without sacrificing any of the quality controls required to ensure our customers' satisfaction. We have scoured our timber operations to capture, as much as possible, the by-products that result from these activities. We are able to turn materials that may appear to be waste into valuable end products. For example, the tree bark is collected and sold to nurseries and landscapers for mulch, and the wood chips are gathered and sold to the paper industry for pulp. Even the sawdust is captured and eventually fused into pellets used by wood pellet stove owners.





Also consistent with the values we hold within our other segments, we place tremendous importance on the environmental factors related to our timber operations. All of our activities are conducted under the watchful eyes of professional foresters and we remain committed to the responsible stewardship of this resource.

Energy Marketing

Our Energy Marketing segment retained its long-standing position as the largest marketer on the Company's utility system. Earnings in 2005 were $5.1 million, representing a slight decrease from last year's earnings of $5.5 million. This segment's continued sound performance comes during a time of unprecedented increases in natural gas commodity prices.

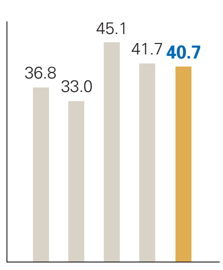
While maintaining its strong share in the wholesale and industrial markets as a non-utility energy supplier, this segment responded to consumers' concerns with a number of open enrollment programs for both residential and business customers on the Utility's system. During fiscal 2005, a Preferred Supplier Program was implemented with a number of regional Chambers of Commerce. These programs offered a variety of pricing strategies to help residential and business customers gain security and control over their energy needs. In the wake of Hurricane Katrina, this segment's solid gas supply planning process ensured that all its retail customers went without interruption, even during recent extreme market conditions.

In 2005, our Energy Marketing segment continued its expansion into central New York via a significant contract with Crucible Specialty Metals in Syracuse, N.Y. One of the largest employers in the region, Crucible selected National Fuel Resources (NFR) as its energy supplier because of NFR's experience, service and reliability. Pictured are Crucible's Corporate Director of Accounting, Michael Costello (right), and NFR's Senior Energy Consultant, Jim Lalley.

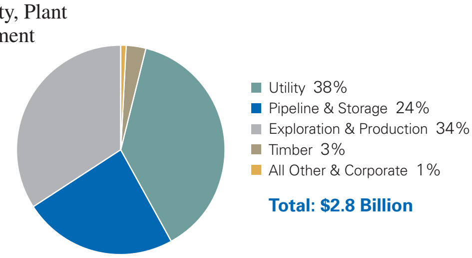
The Energy Marketing segment continued its expansion initiatives into central New York. Crucible Specialty Metals, a leading manufacturer in Syracuse, New York, was added to the segment's customer portfolio and represents an additional 1.3 Bcf in annual volume.

With its strong management team and experienced staff, this segment provides the solid financial footing and competitive advantages needed to succeed in today's energy services marketplace. This segment remains a key player in the value chain as it brings energy marketing services to thousands of residential, commercial and industrial customers throughout the utility systems in western and central New York and northwestern Pennsylvania.

National Fuel Resources' Marketing Volumes
(Bcf)



Net Property, Plant and Equipment
(By Segment)



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, 2005

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

For the Transition Period from to

Commission File Number 1-3880

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

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

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

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

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, $1 Par Value, and Common Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:
None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

If this report is an annual or transition report, indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934. 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 an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ☑ No ☐

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

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $2,343,563,000 as of March 31, 2005.

Common Stock, $1 Par Value, outstanding as of November 30, 2005: 84,461,261 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for the Annual Meeting of Shareholders to be held February 16, 2006 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

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

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

Toro Toro Partners, LP

U.E. United Energy, a.s.

Regulatory Agencies

EPA United States Environmental Protection Agency

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

NYPSC State of New York Public Service Commission

PaPUC Pennsylvania Public Utility Commission

SEC Securities and Exchange Commission

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

Bcf Billion cubic feet

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 (a price, interest rate, index rate, exchange rate, or other variable) and notional amount (number of units, pounds, bushels, 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 Dekatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.

Energy Policy Act Energy Policy Act of 2005

Exchange Act Securities Exchange Act of 1934, as amended

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

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

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

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

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.

Holding Company Act Public Utility Holding Company Act of 1935, as amended

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

Mcf Thousand cubic feet

MD&A Management's Discussion and Analysis of Financial Condition and Results of Operations

MDth Thousand dekatherms

MMcf Million cubic feet

MMcfe Million cubic feet equivalent

NYMEX New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.

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

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

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

PRP Potentially responsible party

Repatriate To return to the country of origin.

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 pipelines separate (or "unbundled") gas commodity service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.

SFAS Statement of Financial Accounting Standards

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

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

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

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

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

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 the cost of only 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, customers are assessed a surcharge. If temperatures during the measured period are colder than normal, customers receive a credit.

For the Fiscal Year Ended September 30, 2005

CONTENTS

This Form 10-K contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements included in this Form 10-K at Item 7, MD&A, under the heading "Safe Harbor for Forward-Looking Statements." Forward-looking statements are all statements other than statements of historical fact, including, without limitation, those statements that are designated with an asterisk ("*") following the statement, as well as those statements that are identified by the use of the words "anticipates," "estimates," "expects," "intends," "plans," "predicts," "projects," and similar expressions.

PART I

Item 1 *Business*

The Company and its Subsidiaries

National Fuel Gas Company (the Registrant) is a holding company organized under the laws of the State of New Jersey. Incorporated in 1902, the Registrant registered in 1935 as a holding company under the Public Utility Holding Company Act of 1935, as amended (the Holding Company Act). Except as otherwise indicated below, the Registrant owns 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 731,000 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation (Supply Corporation), a Pennsylvania corporation, and Empire State Pipeline (Empire), a New York joint venture between two wholly-owned subsidiaries of the Company. Supply Corporation provides interstate natural gas transportation and storage services for affiliated and nonaffiliated companies through (i) an integrated gas pipeline system extending from southwestern Pennsylvania to the New York-Canadian border at the Niagara River and eastward to Ellisburg and Leidy, Pennsylvania, and (ii) 28 underground natural gas storage fields owned and operated by Supply Corporation as well as four other underground natural gas storage fields owned and operated jointly with various other interstate gas pipeline companies. Empire, an intrastate pipeline company, transports natural gas for Distribution Corporation and for other utilities, large industrial customers and power producers in New York State. Empire owns a 157-mile pipeline that extends from the United States/Canadian border at the Niagara River near Buffalo, New York to near Syracuse, New York. The Company acquired Empire in February 2003.

3. The Exploration and Production segment operations are carried out by Seneca Resources Corporation (Seneca), a Pennsylvania corporation. Seneca is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in the Gulf Coast region of Texas, Louisiana, and Alabama. Also, Exploration and Production operations are conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada by Seneca Energy Canada Inc. (SECI), an Alberta, Canada corporation and a subsidiary of Seneca. At September 30, 2005, the Company had U.S. and Canadian reserves of 60,257 Mbbl of oil and 238,140 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, 2005, the Company owned and managed approximately 100,000 acres of timber property.

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 I — 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 engaged 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 pursuing 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. Further information can be found in Item 8 at Note K — Acquisitions;

- 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 which provides collection services principally for the Company's subsidiaries;

- Horizon Power, Inc. (Horizon Power), a New York corporation which is designated as an "exempt wholesale generator" under the Holding Company Act 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 heading "Investing Cash Flow").*

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2005.

Rates and Regulation

Until February 8, 2006, the Company is subject to regulation by the SEC under the broad regulatory provisions of the Holding Company Act, including provisions relating to the issuance of securities, sales and acquisitions of securities and utility assets, intra-company transactions and limitations on diversification. Pursuant to the Energy Policy Act , which President Bush signed into law on August 8, 2005, the Holding Company Act will be repealed effective February 8, 2006. As of that date, the Company will no longer be subject to regulation by the SEC under the Holding Company Act. The Energy Policy Act, among other things, grants the FERC and state public utility commissions access to certain books and records of companies in holding company systems, provides (upon request of a state commission or holding company system) for FERC review of allocations of costs of non-power goods and administrative services in electric utility holding company systems, and modifies the jurisdiction of FERC over certain mergers and acquisitions involving public utilities or holding companies. The Company is unable to predict at this time what the ultimate outcome of these or future legislative or regulatory changes will be. The Company is still in the process of analyzing the effect of the Energy Policy Act on the Company, including the effects of any related proceeding at the state level and new regulations at the federal level.

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 Matters" and Item 8 at Note B-Regulatory Matters.

The Pipeline and Storage segment's rates, services and other matters are currently regulated by the FERC with respect to Supply Corporation and by the NYPSC with respect to Empire. On October 11, 2005, Empire filed an application with the FERC for the authority to build and operate an extension of its natural gas pipeline (the Empire Connector). If the FERC grants that application and the Company builds and commences operations of the Empire Connector, Empire will at that time become a FERC-regulated pipeline company.* For additional discussion of the Pipeline and Storage segment's rates and regulation, see Item 7, MD&A under the heading "Rate Matters" and Item 8 at Note B-Regulatory Matters. For further discussion of the Empire Connector project, refer to Item 7, MD&A under the heading "Investing Cash Flow."

The discussion under Item 8 at Note B-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 25.5% of the Company's 2005 income from continuing operations and 20.7% of the Company's 2005 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" 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 39.4% of the Company's 2005 income from continuing operations and 31.9% of the Company's 2005 net income available for common stock.

Supply Corporation has service agreements for all of its firm storage capacity, which totals approximately 68,407 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 36,654 MDth or 53.6% of the total firm storage capacity. Following an industry trend, most of Supply Corporation's storage and transportation services are performed under contracts that allow Supply Corporation or the shipper to terminate the contract upon six or twelve months' notice effective at the end of the contract term, and from time to time thereafter. At the beginning of 2006, approximately 86.3% of Supply Corporation's total firm storage capacity (including 44% of Supply's total firm storage capacity contracted for by affiliated shippers) was committed under contracts that could have expired or been terminated before the end of 2006. Based on contract expirations and termination notifications received before the deadline for termination effective within 2006, contracts representing less than 0.5% of Supply Corporation's total firm storage capacity will be terminated during 2006.* Supply Corporation has been successful in marketing and obtaining executed contracts for storage service (at discounted rates when necessary) as it becomes available and expects to continue to do so.*

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 different transportation paths and receipt/delivery point combinations are identified by the market. Supply Corporation currently has firm transportation service agreements for approximately 2,212 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,123 MDth per day or 50.7% of contracted transportation capacity, and the Energy Marketing segment represents another 73 MDth per day or 3.3% of contracted transportation capacity. The remaining 1,016 MDth or 46.0% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2006, 52.9% of Supply Corporation's contracted transportation capacity was committed under affiliate contracts that could have expired or been terminated effective before the end of 2006. Based on contract expirations and termination notices received before the deadline for termination effective within 2006, affiliate contracts representing 5.9% of contracted transportation capacity will actually expire or be terminated effective during 2006. Similarly, 30.7% of contracted transportation capacity was committed under unaffiliated shipper contracts that could have expired or been terminated effective before the end of 2006. Based on contract expirations and termination notices received before the deadline for termination effective within 2006, unaffiliated contracts representing 11.3% of contracted transportation capacity will actually expire or be terminated effective during 2006. Supply Corporation has been successful in marketing and obtaining executed contracts for such transportation service previously (at discounted rates when necessary), and expects to continue to do so.*

Empire has service agreements for the 2005-2006 winter period for all of its firm transportation capacity, which totals approximately 579 MDth per day. Empire provides service under both annual (12 months/year) and seasonal (winter or summer only) contracts. Approximately 87.1% of Empire's firm contracted transportation capacity is on an annual long-term basis. None of Empire's annual long-term agreements are scheduled to expire during 2006. Approximately 3.7% of Empire's firm contracted transportation capacity is under multi-year seasonal contracts, and contracts for about a third of that 3.7% will expire before the end of 2006. The remaining capacity, which represents 9.2% of Empire's firm contracted transportation capacity, is under single season or annual contracts which will expire before the end of 2006. 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 9.3% of Empire's firm contracted transportation capacity, and the Energy Marketing segment accounts for approximately 1.2% of Empire's firm contracted transportation capacity, with the remaining 89.5% 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" 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 33.0% of the Company's 2005 income from continuing operations and 26.7% of the Company's 2005 net income available for common stock.

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

The Energy Marketing Segment

The Energy Marketing segment contributed approximately 3.3% of the Company's 2005 income from continuing operations and 2.7% of the Company's 2005 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" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Timber Segment

The Timber segment contributed approximately 3.3% of the Company's 2005 income from continuing operations and 2.7% of the Company's 2005 net income available for common stock.

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

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss in 2005. The impact of this net loss in relation to the Company's 2005 income from continuing operations was negative 4.5% and in relation to the Company's 2005 net income available for common stock was negative 3.6%.

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

Discontinued Operations

In July 2005, Horizon B.V. sold its entire 85.16% interest in United Energy, a.s. (U.E.), a district heating and electric generation business in the Czech Republic. United Energy's operations are presented in the Company's financial statements as discontinued operations. Including the gain from the sale of U.E., these operations contributed approximately 18.9% of the Company's 2005 net income available for common stock.

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 2005, the Utility segment purchased 88 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 76% of the core market purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for the remaining 24% of the Utility segment's 2005 core market purchases. Purchases from Conoco Phillips Company (17%) and Occidental Energy Marketing, Inc. (16%) accounted for 33% of the Utility's 2005 core market gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2005.

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" 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 I-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. Approximately 57% of the timber processed during 2005 came from land owned by the Company.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2005, this segment purchased 43 Bcf of natural gas, of which 41 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, southwest 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 impact the Energy Policy Act will have on the Company or what the impact of any further restructuring in response to legislation or other events may be.*

The Company competes on the basis of price, service and reliability, product performance and other factors. Sources and providers of energy, other than those described under this "Competition" heading, do not compete with the Company to any significant extent.*

Competition: The Utility Segment

The changes precipitated by the FERC's restructuring of the natural gas industry in Order No. 636, which was issued in 1992, continue to reshape the roles of the gas utility industry and the state regulatory commissions. In both New York and Pennsylvania, Distribution Corporation has retained substantial numbers of residential and small commercial customers as sales customers. However, for many years almost all the industrial and a substantial number of commercial customers have purchased their gas supplies from marketers and utilized Distribution Corporation's gas transportation services. Regulators in both New York and Pennsylvania have adopted retail competition programs for natural gas supply purchases by the remaining utility sales customers. To date, the Utility segment's traditional distribution function remains largely unchanged; however, the NYPSC has stepped up its efforts to encourage customer choice at the retail residential level. In New York, the Utility segment has instituted a number of programs to accommodate more widespread customer choice. In Pennsylvania, the PaPUC issued a report in October 2005 that concluded "effective competition" does not exist in the retail natural gas supply market statewide. The PaPUC plans to reconvene a stakeholder group to explore ways to increase the participation of retail customers in choice programs.

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 (i.e., bypass). In addition, competition continues with fuel oil suppliers and may increase with electric utilities making retail energy sales.*

The Utility segment competes, through its unbundled flexible services, in its most vulnerable markets (the large commercial and industrial markets).* The Utility segment continues to (i) develop or promote new sources and uses of natural gas or new services, rates and contracts and (ii) emphasize and provide high quality service to its customers.

Competition: The Pipeline and Storage Segment

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

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

Competition: The Exploration and Production Segment

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

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

Competition: The Energy Marketing Segment

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy management services. Competition in this area is well developed with regard to price and services from both local and regional 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 both nationally and internationally.

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

Volumes transported and stored by Supply Corporation may vary materially depending on weather, without materially affecting its revenues. Supply Corporation's allowed rates are based on a straight fixed-variable rate design which allows recovery of fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover only the variable costs associated with actual transportation or storage of gas.

Volumes transported by Empire may vary materially depending on weather, and can have a moderate effect on its revenues. Empire's allowed rates are based on a modified fixed-variable rate design, which allows recovery of most fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover variable costs associated with actual transportation of gas, to recover return on equity, and to recover income taxes.

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

The activities of the Timber segment vary on a seasonal basis and are subject to weather constraints. Traditionally, the timber harvesting season occurs when timber growth is dormant and runs from approximately September to March. The operations conducted in the summer months typically focus on pulpwood and on thinning out lower-grade species from the timber stands to encourage the growth of higher-grade species. During 2005, the Timber segment's cutting schedule generally reflected the seasonality of the industry, with 33% of the segment's harvest occurring in the second fiscal quarter.

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 "Other Matters" and in Item 8, Note G — Commitments and Contingencies.

Miscellaneous

The Company and its wholly-owned or majority-owned subsidiaries had a total of 2,044 full-time employees at September 30, 2005, with 2,018 employees in all of its U.S. operations and 26 employees in its Canadian operations at SECI. This is a decrease of 30% from the 2,918 total employed at September 30, 2004. Almost all of the decrease resulted from the Company's sale in July 2005 of U.E.

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

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

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

Executive Officers of the Company as of November 15, 2005(1)

Name and Age (as of September 30, 2005)	Current Company Positions and Other Material Business Experience During Past Five Years
Philip C. Ackerman (61)	Chairman of the Board of Directors since January 2002; Chief Executive Officer since October 2001; President since July 1999; and President of Horizon since September 1995. Mr. Ackerman has served as a Director since March 1994, and previously served as Senior Vice President from June 1989 to July 1999 and President of Distribution Corporation from October 1995 to July 1999.
David F. Smith (52)	President of Supply Corporation since April 2005; President of Empire since April 2005; Vice President of the Company since April 2005. Mr. Smith previously served as President of Distribution Corporation from July 1999 to April 2005; Senior Vice President of Supply Corporation from July 2000 to April 2005; and Senior Vice President of Distribution Corporation from January 1993 to July 1999.
Dennis J. Seeley (62)	President of Distribution Corporation since April 2005; Vice President of the Company since April 2005. Mr. Seeley previously served as President of Supply Corporation from March 2000 to April 2005; President of Empire from February 2003 to April 2005; and Senior Vice President of Distribution Corporation from February 1997 to April 2005. Mr. Seeley also served as Vice President of the Company from January 2000 to April 2000.
James A. Beck (58)	President of Seneca since October 1996 and President of Highland since March 1998.
Ronald J. Tanski (53)	Treasurer of the Company since April 2004; Controller of the Company from February 2003 through March 2004; Senior Vice President of Distribution Corporation since July 2001; Controller of Distribution Corporation from February 1997 through March 2004; Treasurer of Distribution Corporation since April 2004; Treasurer and Secretary of Supply Corporation since April 2004; Secretary and Treasurer of Horizon since February 1997; and Vice President of Distribution Corporation from April 1993 to July 2001.
Karen M. Camiolo (46)	Controller 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 (52)	Secretary of the Company since October 1995; Senior Vice President of Distribution Corporation since July 2001; and Vice President of Distribution Corporation from June 1994 to July 2001.
Paula M. Ciprich (45)	General Counsel of the Company since January 2005; Assistant Secretary and General Counsel of Distribution Corporation since February 1997.
Donna L. DeCarolis (46)	President of NFR since January 2005; Secretary of NFR since March 2002; Vice President of NFR from May 2001 to January 2005; and Assistant Vice President of Distribution Corporation from June 1999 to May 2001.
John R. Pustulka (53)	Senior Vice President of Supply Corporation since July 2001; and Vice President of Supply Corporation from April 1993 to July 2001.
James D. Ramsdell (50)	Senior Vice President of Distribution Corporation since July 2001; and Vice President of Distribution Corporation from June 1994 to 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 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 has relied, and continues to rely, upon shorter term bank borrowings to finance the execution of a portion of its operating strategies. National Fuel is dependent on these capital sources to provide capital to its subsidiaries to allow them to acquire and develop their properties. The availability and cost of these credit sources is cyclical and these capital sources may not remain available to National Fuel or National Fuel may not be able to obtain money at a reasonable cost in the future. National Fuel's ability to borrow under its credit facilities depends on National Fuel's compliance with its obligations under the facilities. In addition, all of National Fuel's 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 bank debt other than at the project level of Empire, where there is an interest rate collar on the approximate $32.1 million of project debt (at September 30, 2005). In addition, the interest rates on National Fuel's bank loans 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 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, Distribution Corporation's revenue growth will be limited and its earnings may decrease.

In addition to their historical methods of utility regulation, both the PaPUC and NYPSC have sought to establish competitive markets in which customers may purchase supplies of gas from marketers, rather than from utility companies. In June 1999, the Governor of Pennsylvania signed into law the Natural Gas Choice and Competition Act. The act revised the Public Utility Code relating to the restructuring of the natural gas industry. The purpose of the law was to permit consumer choice of natural gas suppliers. To a certain degree, the early programs instituted to comply with the Act have not been overly successful, and many residential customers currently continue to purchase natural gas from the utility companies. In October 2005 the PaPUC concluded that "effective competition" does not exist in the retail natural gas supply market statewide. The PaPUC plans to reconvene a stakeholder group to explore ways to increase the participation of retail customers in choice programs. In New York, in August 2004, the NYPSC issued its Statement of Policy on Further Steps Toward Competition in Retail Energy Markets. This policy statement has a similar goal of encouraging customer choice of alternative natural gas providers. In 2005, the NYPSC stepped up its efforts to encourage customer choice at the retail residential level. These new forms of regulation may increase Distribution Corporation's cost of doing business, put an additional portion of its business at regulatory risk, and create uncertainty for the future, all of which may make it more difficult to manage Distribution Corporation's business profitably.

In its Pipeline and Storage segment, National Fuel is subject to the jurisdiction of the FERC with respect to Supply Corporation, and to the jurisdiction of the NYPSC with respect to Empire. These regulatory commissions, among other things, approve the rates that Supply Corporation may charge to its natural gas transportation and storage customers. Those approved rates also impact the returns that Supply Corporation 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 is required in a rate proceeding to reduce the rates it charges its natural gas transportation and storage customers, or if Supply Corporation is unable to obtain approval for rate increases, particularly when necessary to cover increased costs, Supply Corporation's revenue growth will be limited and its earnings may decrease.

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

Tariff rate schedules in each of the Utility segment's service territories contain purchased gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased gas. Assuming those rate adjustments are granted, increases in the cost of purchased gas have no direct impact on profit margins. Nevertheless, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of National Fuel's capital resources. National Fuel has issued commercial paper and used short-term borrowings in the past to temporarily finance storage inventories and purchased gas costs, and National Fuel expects to do so in the future.* Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased gas. Due to the nature of the regulatory process, there is a risk of a disallowance of full recovery of these costs during any period in which there has been a substantial upward spike in these costs. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings. In addition, even when Distribution Corporation is allowed full recovery of these purchased gas costs, during periods when natural gas prices are significantly higher than historical levels, customers may have trouble paying the resulting higher bills, and Distribution Corporation's bad debt expenses may increase and ultimately reduce earnings.

Uncertain economic conditions may affect National Fuel's ability to finance capital expenditures and to refinance maturing debt.

National Fuel's ability to finance capital expenditures and to refinance maturing debt will depend upon general economic conditions in the capital markets. The direction in which interest rates may move is uncertain. Declining interest rates have generally been believed to be favorable to utilities, while rising interest rates are generally believed to be unfavorable, because of the levels of debt that utilities may have outstanding. In addition, National Fuel's authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, National Fuel's authorized rate of return could be reduced. If interest rates are higher than assumed rates, National Fuel's ability to earn its authorized rate of return may be adversely impacted.

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

National Fuel's exploration and production operations are materially dependent on prices received for its oil and natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and natural gas. Oil and natural gas prices can be volatile and can be affected by: weather conditions, including natural disasters; the supply and price of foreign oil and natural gas; the level of consumer product demand; national and worldwide economic conditions; 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, which include: weather conditions; the supply and price of foreign oil and natural gas; the level of consumer product demand; worldwide economic conditions, including economic disruptions caused by terrorist activities or acts of war; political conditions in foreign countries; the price and availability of alternative fuels; the proximity to and capacity of transportation facilities; worldwide energy conservation measures; and government regulations, such as regulation of natural gas transportation and price controls. National Fuel believes that any prolonged reduction in oil and natural gas prices would restrict its ability to continue the level of activity National Fuel otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.*

National Fuel has significant transactions involving price hedging of its oil and natural gas production.

In order to protect itself to some extent against unusual price volatility and to lock in fixed pricing on oil and natural gas production for certain periods of time, National Fuel periodically enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may at any time cover as much as 70% of National Fuel's expected energy production during the upcoming 12 month period. These contracts reduce exposure to subsequent price drops but can also limit National Fuel's ability to benefit from increases in commodity prices.

In addition, under the applicable accounting rules, such hedging arrangements are subject to quarterly effectiveness tests. Inherent within those effectiveness tests are assumptions concerning the long-term price differential between different types of crude oil, assumptions concerning the difference between published natural gas price indexes established by pipelines in which hedged natural gas production is delivered and the reference price established in the hedging arrangements, and assumptions regarding the levels of production that will be achieved. Depending on market conditions for natural gas and crude oil and the levels of production actually achieved, it is possible that certain of those assumptions may change in the future, and, depending on the magnitude of any such changes, it is possible that a portion of the Company's hedges may no longer be considered highly effective. In that case, gains or losses from the ineffective derivative financial instruments would be marked-to-market on the income statement without regard to an underlying physical transaction. Gains would occur to the extent that hedge prices exceed market prices, and losses would occur to the extent that market prices exceed hedge prices.

Use of energy commodity price hedges also exposes National Fuel to the risk of non-performance by a contract counterparty. National Fuel carefully evaluates the financial strength of all contract counterparties, but these parties might not be able to perform their obligations under the hedge arrangements.

It is National Fuel's policy that the use of commodity derivatives contracts be strictly confined to the price hedging of existing and forecast production, and National Fuel maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades could occur that may expose National Fuel to substantial losses to cover positions in these contracts.

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 reviewed 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 lower estimates of proved reserves. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to National Fuel's reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of National Fuel's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

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

Petroleum engineering is a subjective process of estimating underground accumulations of natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to National Fuel's future reserve estimates. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of oil and natural gas that are ultimately recovered, the timing of the recovery of oil and natural gas reserves, the production and operating costs incurred, the amount and timing of future development expenditures, and the price received for the production.

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

There are many risks in developing oil and natural gas, including numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of National Fuel's Exploration and Production segment depends on its ability to develop additional oil and natural gas reserves that are economically recoverable, and its failure to do so may reduce National Fuel's earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. National Fuel's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, geology, and other factors. Drilling for natural gas can be unprofitable, not only from dry wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells is often uncertain, and new wells may not be productive or National Fuel may not recover all or any portion of its investment. Without continued successful exploitation or acquisition activities, National Fuel's reserves and revenues will decline as a result of its current reserves being depleted by production. National Fuel cannot assure you that it will be able to find or acquire additional reserves at acceptable costs.

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

National Fuel accounts for its exploration and production activities under the full-cost method of accounting. Each quarter, on a country-by-country basis, National Fuel must compare the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future revenues, such investment may be considered to be "impaired," and the full-cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance, if it were to occur, would require National Fuel to recognize an immediate expense in that quarter, and its earnings would be reduced. 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 if, or when, it may be affected by such an impairment calculation.

Environmental regulation significantly affects National Fuel's business.

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

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

National Fuel's operations are subject to inherent hazards and risks such as: fires; natural disasters; explosions; formations with abnormal pressures; blowouts; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage 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, personal injury or death claims, damage to National Fuel's properties or damage to the properties of others. 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 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. Furthermore, such hazards, risks, insurance and indemnification may subject National Fuel to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against National Fuel or be resolved on unfavorable terms, the result of which could have a material adverse effect on National Fuel's results of operations, financial condition and cash flows.

National Fuel may be adversely affected by economic conditions.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect National Fuel's revenues and cash flows or restrict its future growth. Economic conditions in National Fuel's utility service territories also impact its collections of accounts receivable.

Item 1B *Unresolved Staff Comments*

None

Item 2 *Properties*

General Information on Facilities

The investment of the Company in net property, plant and equipment was $2.8 billion at September 30, 2005. 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, in the Gulf Coast region of Texas, Louisiana, and Alabama and in the provinces of Alberta, Saskatchewan and British Columbia in Canada. The remaining investment in net property, plant and equipment consisted primarily of the Timber segment (3%) which is located primarily in northwestern Pennsylvania, and All Other and Corporate operations (1%). During the past five years, the Company has made additions to property, plant and equipment in order to expand and improve transmission and distribution facilities for both retail and transportation customers. Net property, plant and equipment has increased $156.0 million, or 6%, since 2000. During 2005, the Company sold its majority interest in U.E., a district heating and electric generation business in the Czech Republic. Excluding the impact of that sale, net property, plant and equipment has increased $328.0 million, or 13%, since 2000.

The Utility segment had a net investment in property, plant and equipment of $1.1 billion at September 30, 2005. The net investment in its gas distribution network (including 14,784 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, 2005.

The Pipeline and Storage segment had a net investment of $680.6 million in property, plant and equipment at September 30, 2005. Transmission pipeline represents 37% of this segment's total net investment and includes 2,533 miles of pipeline required to move large volumes of gas throughout its service area. Storage facilities consist of 32 storage fields, four of which are jointly owned and operated with certain pipeline suppliers, and 439 miles of pipeline. Net investment in storage facilities includes $90.9 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 75,081 installed compressor horsepower.

The Exploration and Production segment had a net investment in property, plant and equipment of $974.8 million at September 30, 2005. Of this amount, $803.9 million relates to properties located in the United States. The remaining net investment of $170.9 million relates to properties located in Canada.

The Timber segment had a net investment in property, plant and equipment of $94.8 million at September 30, 2005. Located primarily in northwestern Pennsylvania, the net investment includes two sawmills, approximately 100,400 acres of land and timber, and approximately 4,200 timber rights acres.

The Utility and Pipeline and Storage segments' facilities provided the capacity to meet the Company's 2005 peak day sendout, including transportation service, of 1,672.2 MMcf, which occurred on January 21, 2005. Withdrawals from storage of 662.5 MMcf provided approximately 39.6% of the requirements on that day.

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

Exploration and Production Activities

The Company is engaged in the exploration for, and the development and purchase of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in the Gulf Coast region of Texas, Louisiana, and Alabama. Also, Exploration and Production operations are conducted in the provinces of Alberta, Saskatchewan and British Columbia in Canada. Further discussion of oil and gas producing activities is included in Item 8, Note O-Supplementary Information for Oil and Gas Producing Activities. Note O sets forth proved developed and undeveloped reserve information for Seneca. Seneca's proved developed and undeveloped natural gas reserves increased from 225 Bcf at September 30, 2004 to 238 Bcf at September 30, 2005. This increase can be attributed to the fact that net extensions and discoveries outpaced production. However, Seneca's proved developed and undeveloped oil reserves decreased from 65,213 Mbbl at September 30,2004 to 60,257 Mbbl at September 30, 2005. This decrease can be attributed to the fact that production outpaced net extensions and discoveries. During 2004, Seneca's proved developed and undeveloped reserves decreased modestly from the prior year. Natural gas reserves decreased from 251 Bcf at September 30, 2003 to 225 Bcf at September 30, 2004 and oil reserves decreased from 69,764 Mbbl to 65,213 Mbbl. These decreases are attributed primarily to the fact that U.S. and Canadian production outpaced net extensions and discoveries.

Seneca's oil and gas reserves reported in Note O as of September 30, 2005 were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Ralph E. Davis Associates, Inc. Seneca reports its oil and gas reserve information on an annual basis to the Energy Information Administration (EIA), a statistical agency of the U.S. Department of Energy. The basis of reporting Seneca's reserves to the EIA is identical to that reported in Note O.

The following is a summary of certain oil and gas information taken from Seneca's records. All monetary amounts are expressed in U.S. dollars.

Production

	For the Year Ended September 30		
	2005	2004	2003
United States			
Gulf Coast Region			
Average Sales Price per Mcf of Gas	$ 7.05	$ 5.61	$ 5.41
Average Sales Price per Barrel of Oil	$49.78	$35.31	$29.17
Average Sales Price per Mcf of Gas (after hedging)	$ 6.01	$ 4.82	$ 4.22
Average Sales Price per Barrel of Oil (after hedging)	$35.03	$31.51	$27.88
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.71	$ 0.60	$ 0.56
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	50	73	75
West Coast Region			
Average Sales Price per Mcf of Gas	$ 6.85	$ 5.54	$ 5.01
Average Sales Price per Barrel of Oil	$42.91	$31.89	$26.12
Average Sales Price per Mcf of Gas (after hedging)	$ 6.15	$ 5.72	$ 5.12
Average Sales Price per Barrel of Oil (after hedging)	$23.01	$22.86	$23.67
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.15	$ 1.05	$ 1.00
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	53	55	59
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 7.60	$ 5.91	$ 5.07
Average Sales Price per Barrel of Oil	$48.28	$31.30	$28.77
Average Sales Price per Mcf of Gas (after hedging)	$ 7.01	$ 5.72	$ 5.10
Average Sales Price per Barrel of Oil (after hedging)	$48.28	$31.30	$28.77
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.63	$ 0.54	$ 0.43
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	13	14	14
Total United States			
Average Sales Price per Mcf of Gas	$ 7.13	$ 5.66	$ 5.28
Average Sales Price per Barrel of Oil	$44.87	$33.13	$27.16
Average Sales Price per Mcf of Gas (after hedging)	$ 6.26	$ 5.13	$ 4.52
Average Sales Price per Barrel of Oil (after hedging)	$26.59	$26.06	$25.11
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.90	$ 0.76	$ 0.72
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	117	142	148

	For the Year Ended September 30		
	2005	2004	2003
Canada			
Average Sales Price per Mcf of Gas	$ 6.15	$ 4.87	$ 4.67
Average Sales Price per Barrel of Oil	$42.97	$30.94	$26.41
Average Sales Price per Mcf of Gas (after hedging)	$ 6.14	$ 4.79	$ 4.20
Average Sales Price per Barrel of Oil (after hedging)	$42.97	$30.94	$15.85
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.29	$ 1.00	$ 1.65
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	27	22	55
Total Company			
Average Sales Price per Mcf of Gas	$ 6.86	$ 5.51	$ 5.18
Average Sales Price per Barrel of Oil	$44.72	$32.98	$26.90
Average Sales Price per Mcf of Gas (after hedging)	$ 6.23	$ 5.06	$ 4.47
Average Sales Price per Barrel of Oil (after hedging)	$27.86	$26.40	$21.84
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.98	$ 0.80	$ 0.97
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	144	164	203

Productive Wells

	United States							
	Gulf Coast Region		West Coast Region		Appalachian Region		Total U. S.	
At September 30, 2005	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	33	35	—	1,248	1,995	31	2,028	1,314
Productive Wells — Net	20	15	—	1,240	1,918	25	1,938	1,280

Productive Wells

	Canada		Total Company	
At September 30, 2005	Gas	Oil	Gas	Oil
Productive Wells — Gross	198	53	2,226	1,367
Productive Wells — Net	141	36	2,079	1,316

Developed and Undeveloped Acreage

	United States					
At September 30, 2005	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
Developed Acreage						
— Gross	111,864	9,839	509,337	631,040	124,143	755,183
— Net	82,695	9,469	482,453	574,617	86,454	661,071
Undeveloped Acreage						
— Gross	178,269	—	479,056	657,325	385,359	1,042,684
— Net	94,251	—	454,513	548,764	254,794	803,558

As of September 30, 2005, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 126,636 acres in 2006 (91,416 net acres), 144,846 acres in 2007

(94,995 net acres), 102,332 acres in 2008 (63,232 net acres), and 668,870 acres thereafter (553,915 net acres).

Drilling Activity

For the Year Ended September 30	Productive 2005	Productive 2004	Productive 2003	Dry 2005	Dry 2004	Dry 2003
United States						
Gulf Coast Region						
Net Wells Completed						
— Exploratory	1.30	—	1.25	0.47	0.50	—
— Development	0.23	0.65	2.10	—	—	—
West Coast Region Net Wells Completed						
— Exploratory	—	—	—	—	—	—
— Development	116.97	49.00	30.97	—	—	—
Appalachian Region Net Wells Completed						
— Exploratory	3.00	—	3.00	4.00	3.00	0.10
— Development	45.00	41.00	58.00	1.00	—	—
Total United States Net Wells Completed						
— Exploratory	4.30	—	4.25	4.47	3.50	0.10
— Development	162.20	90.65	91.07	1.00	—	—
Canada						
Net Wells Completed						
— Exploratory	21.14	52.85	5.00	2.00	6.08	2.50
— Development	3.50	10.50	17.16	—	—	5.00
Total						
Net Wells Completed						
— Exploratory	25.44	52.85	9.25	6.47	9.58	2.60
— Development	165.70	101.15	108.23	1.00	—	5.00

Present Activities

At September 30, 2005	United States: Gulf Coast Region	United States: West Coast Region	United States: Appalachian Region	United States: Total U.S.	Canada	Total Company
Wells in Process of Drilling(1)						
— Gross	7.00	5.00	52.00	64.00	4.00	68.00
— Net	5.04	5.00	52.00	62.04	0.82	62.86

(1) Includes wells awaiting completion.

Item 3 *Legal Proceedings*

In an action instituted in the New York State Supreme Court, Chautauqua County on January 31, 2000 against Seneca, NFR and "National Fuel Gas Corporation," Donald J. and Margaret Ortel and Brian and Judith Rapp, "individually and on behalf of all those similarly situated," allege, in an amended complaint which adds National Fuel Gas Company as a party defendant that (a) Seneca underpaid royalties due under leases operated by it, and (b) Seneca's co-defendants (i) fraudulently participated in and concealed such alleged underpayment, and (ii) induced Seneca's alleged breach of such leases. Plaintiffs seek an accounting, declaratory and related injunctive relief, and compensatory and exemplary damages. Defendants have denied each of plaintiffs' material substantive allegations and set up twenty-five affirmative defenses in separate verified answers.

A motion was made by plaintiffs on July 15, 2002 to certify a class comprising all persons presently and formerly entitled to receive royalties on the sale of natural gas produced and sold from wells operated in New York by Seneca (and its predecessor Empire Exploration, Inc). On December 23, 2002, the court granted certification of the proposed class, as modified to exclude those leaseholders whose leases provide for calculation of royalties based upon a flat fee, or flat fee per cubic foot of gas produced. The court's order states that there are approximately 749 potential class members. Discovery closed on July 31, 2005, and the plaintiffs thereafter filed a formal demand for a jury trial and a "Note of Issue and Statement of Readiness" to proceed to trial. A trial date has not been set.

On October 13, 2005, the Company and the attorneys for the class entered into a Stipulation of Settlement, under which (i) the class would be expanded for purposes of settlement to include similarly situated persons entitled to royalties on natural gas production in Pennsylvania, (ii) the Company would pay $2.25 million to the plaintiffs to settle all damages, interest, legal fees and costs, and (iii) the Company would comply with various procedures set out in the Stipulation regarding the marketing of natural gas produced and the calculation of royalties. A fairness hearing has been scheduled for December 19, 2005 to December 21, 2005, at which interested parties may object to the settlement, following which the judge will rule on whether the settlement is just and reasonable. The Company's balance sheet at September 30, 2005 includes a liability for the $2.25 million settlement.

In an action instituted in the New York State Supreme Court, Kings County on February 18, 2003 against Distribution Corporation and Paul J. Hissin, an unaffiliated third party, plaintiff Donna Fordham-Coleman, as administratrix of the estate of Velma Arlene Fordham, alleges that Distribution Corporation's denial of natural gas service in November 2000 to the plaintiff's decedent, Velma Arlene Fordham, caused decedent's death in February 2001. The plaintiff seeks damages for wrongful death and pain and suffering, plus punitive damages. Distribution Corporation has denied plaintiff's material allegations, set up seven affirmative defenses in separate verified answers and filed a cross-claim against the co-defendant. Distribution Corporation believes, and will vigorously assert, that plaintiff's allegations lack merit. The Court changed venue of the action to New York State Supreme Court, Erie County. Discovery has closed and a trial date has been scheduled for February 27, 2006.

On December 22, 2003, the Pennsylvania Department of Environmental Protection (DEP) issued an order to Seneca to halt its timber harvesting operations on 21,000 acres in Cameron, Elk and McKean counties in Pennsylvania. The order asserts certain violations of DEP regulations concerning erosion, sedimentation and stream crossings. The order requires Seneca to apply for certain permits, control erosion, submit plans for removal of water encroachments not included in permit applications, notify the DEP of additional current or planned timber harvesting operations, and grant the DEP access to timber acreage. On January 9, 2004, Seneca filed with the Pennsylvania Environmental Hearing Board (Hearing Board) a notice of appeal, objecting to each finding and order contained in the order, and asserting that the DEP's findings are factually incorrect, an arbitrary exercise of the DEP's functions and duties, and contrary to law. Also on January 9, 2004, Seneca filed with the Hearing Board a petition requesting a stay of operation of portions of the order. On January 16, 2004, the parties settled Seneca's request for a stay. Seneca has resumed its timber harvesting operations pursuant to the terms of the settlement. The settlement preserves various issues raised by the DEP's order for a hearing on the merits of Seneca's notice of appeal. Seneca is engaged in settlement negotiations as it continues to litigate this matter.* The most substantial question in the appeal involves whether Seneca is required to apply for a permit under Section 102.5(b) of Title 25 of the Pennsylvania Code, governing earth disturbance activities of greater than 25 acres. The DEP takes the position that Seneca must aggregate the acreage of all of its logging sites across its entire 21,000 acre tract for purposes of determining whether its earth disturbing activities meet the 25 acres threshold. Seneca maintains that no permit is required, because the law does not require aggregation and each of its individual logging sites disturbs less than 25 acres.

The Company believes, based on the information presently known, that the ultimate resolution of these matters, individually or in the aggregate, 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 these matters, and it is possible that the outcomes, individually or in the aggregate, could be material to results of operations or cash flow for a particular quarter or annual period.*

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

The Company is involved in litigation arising in the normal course of business. Also in the normal course of business, the Company is involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While the resolution of such litigation or regulatory matters could have a material effect on earnings and cash flows in the period of resolution, none of this litigation, and none of these regulatory matters, are expected to change materially the Company's present liquidity position, nor 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, 2005.

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 D-Capitalization and Short-Term Borrowings and Note N-Market for Common Stock and Related Shareholder Matters (unaudited).

On July 1, 2005, the Company issued a total of 2,100 unregistered shares of Company common stock to the seven non-employee directors of the Company then 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, 2005, 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
July 1-31, 2005	147,800	$29.94	—	—
Aug. 1-31, 2005	31,878	$29.60	—	—
Sept. 1-30, 2005	105,619	$32.26	—	—
Total	285,297	$30.76	—	—

(a) Represents (i) shares of common stock of the Company purchased on the open market with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock options or shares of restricted stock for the payment of option exercise prices and/or applicable withholding taxes.

Item 6 *Selected Financial Data (1)*

	Year Ended September 30				
	2005	2004	2003	2002	2001
			(Thousands)		
Summary of Operations					
Operating Revenues	$1,923,549	$1,907,968	$1,921,573	$1,369,869	$1,962,874
Operating Expenses:					
Purchased Gas	959,827	949,452	963,567	462,857	1,002,466
Operation and Maintenance	404,517	385,519	361,898	372,063	348,270
Property, Franchise and Other Taxes	69,076	68,978	79,692	69,837	81,571
Depreciation, Depletion and Amortization	179,767	174,289	181,329	168,745	163,239
Impairment of Oil and Gas Producing Properties	—	—	42,774	—	180,781
	1,613,187	1,578,238	1,629,260	1,073,502	1,776,327
Gain (Loss) on Sale of Timber Properties	—	(1,252)	168,787	—	—
Gain (Loss) on Sale of Oil and Gas Producing Properties	—	4,645	(58,472)	—	—
Operating Income	310,362	333,123	402,628	296,367	186,547
Other Income (Expense):					
Income from Unconsolidated Subsidiaries	3,362	805	535	224	1,794
Impairment of Investment in Partnership	(4,158)	—	—	(15,167)	—
Interest Income	6,496	1,771	2,204	2,593	4,010
Other Income	12,744	2,908	2,427	3,184	5,337
Interest Expense on Long-Term Debt	(73,244)	(82,989)	(91,381)	(88,646)	(78,297)
Other Interest Expense	(9,069)	(6,763)	(11,196)	(15,109)	(25,294)
Income from Continuing Operations Before Income Taxes	246,493	248,855	305,217	183,446	94,097
Income Tax Expense	92,978	94,590	124,150	69,944	33,434
Income from Continuing Operations	153,515	154,265	181,067	113,502	60,663
Discontinued Operations:					
Income from Operations, Net of Tax	10,199	12,321	6,769	4,180	4,836
Gain on Disposal, Net of Tax	25,774	—	—	—	—
Income from Discontinued Operations, Net of Tax	35,973	12,321	6,769	4,180	4,836
Income Before Cumulative Effect of Changes in Accounting	189,488	166,586	187,836	117,682	65,499
Cumulative Effect of Changes in Accounting	—	—	(8,892)	—	—
Net Income Available for Common Stock	$ 189,488	$ 166,586	$ 178,944	$ 117,682	$ 65,499

	Year Ended September 30				
	2005	2004	2003	2002	2001
			(Thousands)		
Per Common Share Data					
Basic Earnings from Continuing Operations per Common Share	$ 1.84	$ 1.88	$ 2.24	$ 1.42	$ 0.77
Diluted Earnings from Continuing Operations per Common Share	$ 1.81	$ 1.86	$ 2.23	$ 1.41	$ 0.76
Basic Earnings per Common Share(2)	$ 2.27	$ 2.03	$ 2.21	$ 1.47	$ 0.83
Diluted Earnings per Common Share(2)	$ 2.23	$ 2.01	$ 2.20	$ 1.46	$ 0.82
Dividends Declared	$ 1.14	$ 1.10	$ 1.06	$ 1.03	$ 0.99
Dividends Paid	$ 1.13	$ 1.09	$ 1.05	$ 1.02	$ 0.97
Dividend Rate at Year-End	$ 1.16	$ 1.12	$ 1.08	$ 1.04	$ 1.01
At September 30:					
Number of Common Shareholders	18,369	19,063	19,217	20,004	20,345
Net Property, Plant and Equipment *(Thousands)*					
Utility	$1,064,588	$1,048,428	$1,028,393	$ 960,015	$ 945,693
Pipeline and Storage	680,574	696,487	705,927	487,793	483,222
Exploration and Production	974,806	923,730	925,833	1,072,200	1,081,622
Energy Marketing	97	80	171	125	262
Timber	94,826	82,838	87,600	110,624	90,453
All Other	18,098	21,172	22,042	6,797	1,209
Corporate(3)	6,311	234,029	221,082	207,191	178,252
Total Net Plant	$2,839,300	$3,006,764	$2,991,048	$2,844,745	$2,780,713
Total Assets *(Thousands)*	$3,722,652	$3,717,603	$3,725,414	$3,429,163	$3,452,566
Capitalization *(Thousands)*					
Comprehensive Shareholders' Equity	$1,229,583	$1,253,701	$1,137,390	$1,006,858	$1,002,655
Long-Term Debt, Net of Current Portion	1,119,012	1,133,317	1,147,779	1,145,341	1,046,694
Total Capitalization	$2,348,595	$2,387,018	$2,285,169	$2,152,199	$2,049,349

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

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

(3) Includes net plant of the former international segment as follows: $20 for 2005, $227,905 for 2004, $219,199 for 2003, $207,191 for 2002 and $178,250 for 2001.

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

OVERVIEW

The Company is a diversified energy company consisting of five reportable business segments. Refer to Item I, Business, for a more detailed description of each of the segments. This Item 7, MD&A, provides information concerning:

1. The critical accounting policies 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.) 2005 and 2006 funding to the Company's defined benefit retirement plan and post-retirement benefit plan, b.) disclosures and tables concerning market risk sensitive instruments, c.) rate matters in the Company's New York, Pennsylvania and FERC regulated jurisdictions, d.) environmental matters, and e.) 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 2005, and the main reason for the significant earnings increase over 2004, was the Company's sale of its entire 85.16% interest in U.E., a district heating and electric generation business in the Czech Republic. This sale resulted in a $25.8 million gain, net of tax. Current market conditions, 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 determined it appropriate to present the Czech Republic operations as discontinued operations beginning in June 2005. The Company also determined it appropriate to discontinue all reporting for an International segment in June 2005 since the Czech Republic operations represented substantially all of the activity in that segment. Any remaining international activity has been included in corporate operations for all periods presented below.

CRITICAL ACCOUNTING POLICIES

The Company has prepared its consolidated financial statements in conformity with accounting principles generally accepted in the United States of America. 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 policies, which are defined as those policies whereby judgments or uncertainties could affect the application of those policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the Company's significant accounting policies, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

Oil and Gas Exploration and Development Costs. In the Company's Exploration and Production segment, oil and gas property acquisition, exploration and development costs are capitalized under the full cost method of accounting. Under this accounting methodology, all costs associated with property acquisition, exploration and development activities are capitalized, including internal costs directly identified with acquisition, exploration and development activities. The internal costs that are capitalized do not include any costs related to production, general corporate overhead, or similar activities.

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

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. The ceiling test is performed on a country-by-country basis and determines a limit, or ceiling, to the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net revenues using a discount factor of 10%, which is computed by applying current market prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income taxes. The estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions or subtractions to proved reserves and significant fluctuations in oil and gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write-down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. The Company recorded non-cash impairments relating to its Canadian properties in 2003 which amounted to $28.9 million (after tax) and resulted from downward revisions to crude oil reserves (related to the Canadian properties sold) as well as a decline in crude oil prices.

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

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

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

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The fair value of the non exchange-traded derivative financial instruments are based on valuations determined by the counterparties. Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A, 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 reasonably matches the expected timing of anticipated future 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." For further discussion of the Company's pension and other post-retirement benefits, refer to Other Matters in this Item 7 and to Item 8 at Note F — Retirement Plan and Other Post Retirement Benefits.

RESULTS OF OPERATIONS

EARNINGS

2005 Compared with 2004

The Company's earnings were $189.5 million in 2005 compared with earnings of $166.6 million in 2004. As previously discussed, the Company has presented its Czech Republic operations as discontinued operations. Prior year amounts have been reclassified to reflect this change in presentation. The Company's earnings from continuing operations were $153.5 million in 2005 compared with $154.3 million in 2004. The Company's earnings from discontinued operations were $36.0 million in 2005 compared with $12.3 million in 2004. Earnings from continuing operations did not change significantly as higher earnings in the Pipeline and Storage segment were largely offset by lower earnings in the Utility and Exploration and Production segments and a higher loss in the All Other category. The increase in earnings from discontinued operations resulted from the gain on the sale of U.E. in 2005. In the discussion that follows, note that all amounts used in the earnings discussions are after tax amounts. Earnings from continuing operations and discontinued operations were impacted by several events in 2005 and 2004, including:

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.

2004 Events

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

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

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

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

2004 Compared with 2003

The Company's earnings were $166.6 million in 2004 compared with earnings of $178.9 million in 2003. The Company's earnings from continuing operations were $154.3 million in 2004 compared with $181.1 million in 2003. The Company's earnings from discontinued operations were $12.3 million in 2004 compared with $6.8 million in 2003. The Company also reduced earnings by $8.9 million in 2003 associated with the cumulative effect of changes in accounting. The decrease in earnings from continuing operations is primarily the result of lower earnings in the Timber and Utility segments partially offset by higher earnings in the Exploration and Production, and Pipeline and Storage segments, as shown in the table below. Earnings were impacted by the 2004 events discussed above and several events in 2003, including:

2003 Events

- The Company's Timber segment completed the sale of approximately 70,000 acres of its timber property, increasing earnings by $102.2 million;

- The Company's Exploration and Production segment completed the sale of its Southeast Saskatchewan oil and gas properties in Canada, reducing earnings by $39.6 million;

- The Company's Exploration and Production segment recorded impairment charges related to its Canadian oil and gas assets which reduced earnings by $28.9 million;

- An impairment in the amount of $8.3 million, representing the cumulative effect of a change in accounting for goodwill associated with the Company's operations in the Czech Republic; and

• A reduction in the amount of $0.6 million, representing the cumulative effect of a change in accounting for plugging and abandonment costs in the Company's Exploration and Production segment.

For a more complete discussion of the cumulative effect of changes in accounting, refer to Note A — Summary of Significant Accounting Policies in Item 8 of this report. 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		
	2005	2004	2003
		(Thousands)	
Utility	$ 39,197	$ 46,718	$ 56,808
Pipeline and Storage	60,454	47,726	45,230
Exploration and Production	50,659	54,344	(31,293)
Energy Marketing	5,077	5,535	5,868
Timber	5,032	5,637	112,450
Total Reportable Segments	160,419	159,960	189,063
All Other	(2,616)	1,530	193
Corporate(1)	(4,288)	(7,225)	(8,189)
Total Earnings from Continuing Operations	$153,515	$154,265	$181,067
Earnings from Discontinued Operations	35,973	12,321	6,769
Cumulative Effect of Changes in Accounting(2)	—	—	(8,892)
Total Consolidated	$189,488	$166,586	$178,944

(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.

(2) Includes $8.3 million for the cumulative effect of a change in accounting for goodwill associated with the Company's operations in the Czech Republic and $0.6 million for the cumulative effect of a change in accounting for plugging and abandonment costs in the Company's Exploration and Production segment.

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Retail Revenues:			
Residential	$ 868,292	$ 808,740	$ 801,984
Commercial	145,393	137,092	137,905
Industrial	13,998	17,454	23,263
	1,027,683	963,286	963,152
Off-System Sales	—	106,841	107,220
Transportation	83,669	80,563	86,374
Other	5,715	1,951	6,237
	$1,117,067	$1,152,641	$1,162,983

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2005	2004	2003
Retail Sales:			
Residential	66,903	70,109	76,449
Commercial	11,984	12,752	14,177
Industrial	1,387	2,261	3,537
	80,274	85,122	94,163
Off-System Sales	—	16,839	17,999
Transportation	59,770	60,565	64,232
	140,044	162,526	176,394

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Percent (Warmer) Colder Than Prior Year
2005:	Buffalo	6,692	6,587	(1.6)%	0.2%
	Erie	6,243	6,247	0.1%	2.6%
2004:	Buffalo	6,729	6,572	(2.3)%	(7.9)%
	Erie	6,277	6,086	(3.0)%	(10.1)%
2003:	Buffalo	6,815	7,137	4.7%	22.9%
	Erie	6,135	6,769	10.3%	26.9%

2005 Compared with 2004

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

The increase in other operating revenues of $3.8 million is largely related to amounts recorded pursuant to rate settlements with the NYPSC. In accordance with these settlements, Distribution Corporation was allowed to utilize certain refunds from upstream pipeline companies and certain other credits (referred to as the "cost mitigation reserve") to offset certain specific expense items. In 2005, Distribution Corporation utilized $7.8 million of the cost mitigation reserve, which increased other operating revenues, to recover previous undercollections 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 is no earnings impact). This increase to other operating revenues was partially offset 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 recent settlement agreement in New York, the Company determined that it needed to adjust that regulatory liability by $3.1 million (of which $1.0 million was recorded as a reduction of other operating revenues and $2.1 million was recorded as additional interest expense) related to fiscal years 2004 and prior.

2004 Compared with 2003

Operating revenues for the Utility segment decreased $10.3 million in 2004 compared with 2003. This resulted largely from a decrease in transportation revenues of $5.8 million and a decrease in other revenues of $4.3 million. Transportation revenues decreased because of lower volumes being transported as a result of fuel switching, a general economic downturn in the Utility segment's service territory and warmer weather, as shown in the degree day table above. Retail revenues did not change significantly from the prior year as the impact to revenues of lower retail sales volumes was largely offset by the recovery of higher gas costs (gas costs are recovered dollar for dollar in revenues) and a base rate increase in the Utility segment's Pennsylvania jurisdiction. The recovery of higher gas costs resulted from a much higher cost of purchased gas. See further discussion of purchased gas below under the heading "Purchased Gas." Warmer weather and lower customer usage per account were the major factors in the decrease in retail sales volumes. The decrease in retail industrial sales volumes can be attributed to fuel switching and a general economic downturn in the Utility segment's service territory.

The decrease in other operating revenues is largely related to the three-year rate settlement approved by the NYPSC which ended on September 30, 2003. As part of the three-year rate settlement, Distribution Corporation was allowed to utilize certain refunds from upstream pipeline companies and certain other credits (referred to as the "cost mitigation reserve") to offset certain specific expense items. In 2003, Distribution Corporation utilized $7.6 million of the cost mitigation reserve by recording $7.6 million of other operating revenues. While the three-year rate settlement was extended for an additional year, the provisions of the settlement which gave rise to the other operating revenues in 2003 did not continue in 2004, causing other operating revenues to decrease by $7.6 million in 2004. The impact of utilizing a portion of the cost mitigation reserve in revenues in 2003 was offset by an equal amount of operation and maintenance expense and interest expense (thus there is no earnings impact). Partially offsetting this decrease in revenues, in accordance with the three-year rate settlement which ended on September 30, 2003, Distribution Corporation recorded a refund provision of $4.0 million as a reduction of other operating revenues. While the provisions of the settlement were extended for a one-year period, as previously discussed, this refund provision did not recur in 2004 because the New York rate jurisdiction's earnings did not exceed the sharing threshold. The refund provision relates to a 50% sharing with customers of earnings over a predetermined amount.

Earnings

2005 Compared with 2004

The Utility segment's earnings in 2005 were $39.2 million, a decrease of $7.5 million when compared with earnings of $46.7 million in 2004. The major factors driving this decrease were lower weather-normalized usage per customer account in both the New York and Pennsylvania jurisdictions ($8.2 million) and an increase in bad debt expenses of $6.7 million. The increase in bad debt expenses is attributable to the increase in the reserve for doubtful accounts to reflect the increase in final billed balances, as well as the increased age of outstanding receivables heading into the heating season. These negative factors were partially offset by the impact of base rate increases in both New York and Pennsylvania ($3.9 million) and the recording of accrued interest on a pension related asset in accordance with the New York rate case settlement agreement ($2.4 million), as well as the impact of colder than normal weather in Pennsylvania ($1.0 million). The earnings impact of the two out-of-period regulatory adjustments discussed above was largely offset by lower interest expense on borrowings due to lower debt balances.

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

2004 Compared with 2003

The Utility segment's earnings in 2004 were $46.7 million, a decrease of $10.1 million when compared with earnings of $56.8 million in 2003. The major factors driving this decrease were an increase in pension and other post-retirement expenses of $9.9 million, higher bad debt expenses of $3.8 million, warmer weather in the Pennsylvania jurisdiction ($2.5 million), and lower usage per customer account in the New York jurisdiction ($2.2 million). These negative factors were partially offset by the absence of a refund provision in the New York jurisdiction in 2004 related to an earnings sharing mechanism in the New York jurisdiction ($2.6 million), as discussed above. Other offsetting factors included a base rate increase in the Pennsylvania jurisdiction of $1.5 million and lower interest expense of $4.7 million.

The increase in pension and other post-retirement expenses referred to above can be attributed largely to three factors. First, in accordance with a one-year settlement extension commencing on October 1, 2003 in the New York rate jurisdiction (referred to above), the Company was required to record an additional $8.0 million before tax ($5.2 million after tax) of pension and other post-retirement expense for the year ended September 30, 2004 without a corresponding increase in revenues. Second, the Utility segment recorded $2.2 million of expense associated with the settlement of a pension obligation. Third, pension and other post-retirement expenses in the Pennsylvania rate jurisdiction increased by $2.5 million as the rate settlement in that jurisdiction reflected higher pension funding amounts and the amortization of previous other post-retirement deferrals.

In 2004, the WNC preserved $1.0 million of earnings since the weather was warmer than normal in the New York service territory. For 2003, the WNC reduced earnings by approximately $3.8 million because it was colder than normal in the New York service territory.

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 $9.19 per Mcf in 2005, an increase of 26% from the average cost of $7.30 per Mcf in 2004. The average cost of purchased gas in 2004 was 5% higher than the average cost of $6.94 per Mcf in 2003. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Firm Transportation	$117,146	$120,443	$109,508
Interruptible Transportation	4,413	3,084	3,944
	121,559	123,527	113,452
Firm Storage Service	65,320	63,962	63,223
Interruptible Storage Service	267	20	36
	65,587	63,982	63,259
Other	28,713	22,198	24,709
	$215,859	$209,707	$201,420

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2005	2004	2003
Firm Transportation	357,585	338,991	340,925
Interruptible Transportation	14,794	12,692	10,004
	372,379	351,683	350,929

2005 Compared with 2004

Operating revenues for the Pipeline and Storage segment increased $6.2 million in 2005 as compared with 2004. This increase is primarily attributable to higher revenues from unbundled pipeline sales of $5.5 million included in other revenues in the table above, due to higher natural gas prices. Higher cashout revenues of $1.1 million, reported as part of other revenues in the table above, also contributed to the increase. Cashout revenues are completely offset by purchased gas expense. In addition, interruptible transportation revenues increased by $1.3 million, primarily due to an increase in Supply Corporation's gathering revenues, and firm storage revenues increased $1.4 million, primarily due to higher rate agreements contracted with Supply Corporation customers. Offsetting these increases, the decrease in firm transportation revenues of $3.3 million reflects the cancellation of contracts with Supply Corporation by certain large usage non-affiliated customers ($2.6 million) and the Utility segment's cancellation of a portion of its firm transportation with Supply Corporation in April 2005 ($0.6 million). In addition, firm transportation revenues decreased by $1.0 million because Supply Corporation no longer charges customers a surcharge for its membership to the Gas Research Institute (GRI). The decrease in revenues resulting from cancellation of the GRI surcharge was completely offset by lower operation expense. While Supply Corporation's transportation volumes increased during the year, volume fluctuations generally do not have a significant impact on revenues as a result of Supply Corporation's straight fixed-variable rate design. Offsetting the decreases in Supply Corporation's firm transportation revenues was a $1.0 million increase in Empire's firm transportation revenues, primarily due to an increase in transportation volumes.

2004 Compared with 2003

Operating revenues for the Pipeline and Storage segment increased $8.3 million in 2004 as compared with 2003. The acquisition of Empire from Duke Energy Corporation on February 6, 2003 was a significant factor contributing to the revenue increase. For 2004, Empire recorded operating revenues of $33.4 million

($32.3 million in firm transportation revenues, $0.3 million in interruptible transportation revenues and $0.8 million in other revenues). For the period of February 6, 2003 to September 30, 2003, Empire recorded operating revenues of $20.9 million ($19.8 million in firm transportation revenues, $0.8 million in interruptible transportation revenues and $0.3 million in other revenues). Another factor contributing to the increase in operating revenues in the Pipeline and Storage segment was a $5.0 million increase in revenues from unbundled pipeline sales included in other revenues in the table above due to higher natural gas commodity prices and higher volumes. These increases to operating revenues were partially offset by lower intercompany rental income of approximately $6.5 million and lower cashout revenues of $1.3 million, both of which are included in other revenues in the table above. While 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.

Earnings

2005 Compared with 2004

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

The sale of Ellisburg base gas, which amounted to 680 MDth, will open up 680 MDth of space for ongoing storage service. At current market rates, it is expected that future storage service revenues (including related transportation revenues) may increase by approximately $1.0 million per year with almost no increase in operating expenses associated with the higher revenues. The additional storage has already been contracted for, effective April 1, 2005, resulting in approximately $0.5 million of additional storage revenues and related transportation revenues in 2005 compared with 2004.

2004 Compared with 2003

The Pipeline and Storage segment's earnings in 2004 were $47.7 million, an increase of $2.5 million when compared with earnings of $45.2 million in 2003. The increase can be attributed primarily to the earnings impact of the increase in revenues from unbundled pipeline sales of $3.2 million, discussed above, as well as the increased earnings contribution from Empire of $2.8 million. Also, Supply Corporation interest expense decreased by $1.9 million. Offsetting these increases, Supply Corporation recorded $1.8 million of expense associated with the settlement of a pension obligation in 2004. Supply Corporation also experienced an earnings impact associated with higher operation and maintenance expense of $1.5 million.

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Gas (after Hedging)	$181,713	$167,127	$150,982
Oil (after Hedging)	107,801	119,564	147,101
Gas Processing Plant	36,350	28,614	28,879
Other	(2,733)	1,815	1,308
Intrasegment Elimination(1)	(29,706)	(23,422)	(22,956)
	$293,425	$293,698	$305,314

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

Production Volumes

	Year Ended September 30		
	2005	2004	2003
Gas Production *(MMcf)*			
Gulf Coast	12,468	17,596	18,441
West Coast	4,052	4,057	4,467
Appalachia	4,650	5,132	5,123
Canada	8,009	6,228	5,774
	29,179	33,013	33,805
Oil Production *(Mbbl)*			
Gulf Coast	989	1,534	1,473
West Coast	2,544	2,650	2,872
Appalachia	36	20	10
Canada	300	324	2,382
	3,869	4,528	6,737

Average Prices

	Year Ended September 30		
	2005	2004	2003
Average Gas Price/Mcf			
Gulf Coast	$ 7.05	$ 5.61	$ 5.41
West Coast	$ 6.85	$ 5.54	$ 5.01
Appalachia	$ 7.60	$ 5.91	$ 5.07
Canada	$ 6.15	$ 4.87	$ 4.67
Weighted Average	$ 6.86	$ 5.51	$ 5.18
Weighted Average After Hedging(1)	$ 6.23	$ 5.06	$ 4.47
Average Oil Price/Barrel (bbl)			
Gulf Coast	$49.78	$35.31	$29.17
West Coast(2)	$42.91	$31.89	$26.12
Appalachia	$48.28	$31.30	$28.77
Canada	$42.97	$30.94	$26.41
Weighted Average	$44.72	$32.98	$26.90
Weighted Average After Hedging(1)	$27.86	$26.40	$21.84

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

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

2005 Compared with 2004

Operating revenues for the Exploration and Production segment decreased $0.3 million in 2005 as compared with 2004. Oil production revenue after hedging decreased $11.8 million due to a 659 Mbbl decline in production offset partly by higher weighted average prices after hedging ($1.46 per barrel). Most of the decrease in oil production occurred in the Gulf Coast Region (a 545 Mbbl decrease). Gas production revenue after hedging increased $14.6 million. Increases in the weighted average price of gas after hedging ($1.17 per Mcf) more than offset an overall decrease in gas production (3,834 MMcf). Most of the decrease in gas production occurred in the Gulf Coast (a 5,128 MMcf decline). The decreases in Gulf Coast oil and gas production are consistent with the expected decline rates in the region. This decrease in Gulf Coast gas production was partially offset by a 1,781 MMcf increase in Canadian gas production. The increase in Canadian gas production is attributable to the Sukunka 60-E well, in which the Company has a 20% working interest. Other revenues decreased $4.5 million largely due to a $5.1 million mark-to-market adjustment for losses on certain derivative financial instruments that no longer qualified as effective hedges due to the anticipated delays in oil and gas production volumes caused by Hurricane Rita. These volumes were originally forecast to be produced in the first quarter of 2006. The anticipated delays in oil and gas production volumes has caused the Company to lower its production forecast for 2006, from a range of 50 to 55 Bcfe to a range of 46 to 51 Bcfe.*

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.

2004 Compared with 2003

Operating revenues for the Exploration and Production segment decreased $11.6 million in 2004 as compared with 2003. Oil production revenue after hedging decreased $27.5 million due to a 2,209 Mbbl decline in production offset partly by higher weighted average prices after hedging ($4.56 per barrel). Most of the decrease in oil production occurred in Canada (a 2,058 Mbbl decrease) as a result of the September 2003 sale of the Company's Southeast Saskatchewan properties, which is discussed below. Gas production revenue after hedging increased $16.1 million. Increases in the weighted average price of gas after hedging ($0.59 per Mcf) more than offset an overall decrease in gas production. Most of the decrease in gas production occurred in the Gulf Coast (a 845 MMcf decline), which is consistent with the expected decline rates in the region. Lower West Coast production (a 410 MMcf decline), down mainly due to a decline in this segment's South Lost Hills wells, was more than offset by a 454 MMcf increase in Canadian gas production. The increase in Canadian gas production is attributable to additional drilling in East Central Alberta. The decline in the South Lost Hills wells was attributable to the maturing of the wells.

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

2005 Compared with 2004

The Exploration and Production segment's earnings in 2005 were $50.7 million, a decrease of $3.6 million when compared with earnings of $54.3 million in 2004. In 2004, the Company recorded an adjustment to the sale of its Southeast Saskatchewan properties that increased 2004 earnings by $4.6 million. In 2005, the Company recorded a mark-to-market adjustment, as discussed above under "Revenues", that decreased 2005 earnings by $3.3 million. Higher lease operating and depletion expenses also decreased 2005 earnings by $2.1 million and $0.6 million, respectively. The increase in lease operating expenses resulted mainly from increased Canadian production and higher steaming costs associated with heavy crude oil production in the West Coast Region. Depletion expense increased despite a drop in production mostly due to an increase in the per unit depletion rate, which was largely the result of the higher finding and development costs experienced by Seneca in 2005. All of these factors, which collectively resulted in a $10.6 million decrease in 2005 earnings, were partially offset by higher oil and gas revenues, which increased 2005 earnings by $1.8 million. Also, 2005 earnings benefited from higher interest income ($1.8 million) and lower interest expense ($1.2 million). The fluctuations in interest income and interest expense reflect the fact that the Exploration and Production segment has been operating solely within its own cash flow from operations. Short-term borrowings have been eliminated and excess cash has been invested, resulting in higher interest income. This excess cash will be used to fund operations and future capital expenditures.* Lower general and administrative expenses, largely due to lower legal costs, also increased 2005 earnings by $1.0 million.

2004 Compared with 2003

The Exploration and Production segment's earnings in 2004 were $54.3 million, an increase of $86.2 million when compared with a loss of $31.9 million ($31.3 million from continuing operations and $0.6 million included in cumulative effect of changes in accounting) in 2003. Earnings were impacted by a few events. In 2003, the Company sold its Southeast Saskatchewan properties, recording a loss of $39.6 million. In 2004, the Company recorded an adjustment to the sale of its Southeast Saskatchewan properties which increased 2004 earnings by $4.6 million. When the transaction closed in September 2003, the initial proceeds received were subject to an adjustment based on actual working capital and the resolution of certain income tax matters. Those items were resolved with the buyer in 2004 and, as a result, the Company received an additional $4.6 million of sales proceeds. The Company recorded impairment charges of $28.9 million in 2003 related to its Canadian oil and gas properties. Also contributing to the increase was the fact that the loss in 2003 included a charge of $0.6 million representing the cumulative effect of a change in accounting for plugging and abandonment costs. These events sum up to $73.7 million of the overall earnings increase of $86.2 million. The remaining increase can be attributed to decreases in depletion, lease operating, and interest expense of $6.2 million, $15.9 million, and $1.7 million, respectively, which more than offset the earnings impact of a $7.4 million decrease in oil and gas revenues, discussed above, and a $3.2 million increase in income tax expense due to a higher effective tax rate. The decrease in depletion and lease operating expenses primarily reflects the absence of the Company's former Southeast Saskatchewan properties from results of operations in 2004. The decrease in interest expense was the result of lower debt balances. The higher effective tax rate resulted from the elimination of cross-border intercompany loans in September 2003 as a result of the sale of the Southeast Saskatchewan properties.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Natural Gas (after Hedging)	$329,560	$283,747	$304,390
Other	154	602	270
	$329,714	$284,349	$304,660

Energy Marketing Volumes

	Year Ended September 30		
	2005	2004	2003
Natural Gas — (MMcf)	40,683	41,651	45,135

2005 Compared with 2004

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

2004 Compared with 2003

Operating revenues for the Energy Marketing segment decreased $20.3 million in 2004 as compared with 2003. This decrease primarily reflects lower gas sales revenue due to lower throughput, which was the result of warmer weather and the loss of several large volume, but low margin, customers to other marketers.

Earnings

2005 Compared with 2004

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

2004 Compared with 2003

The Energy Marketing segment earnings in 2004 were $5.5 million, a decrease of $0.4 million when compared with earnings of $5.9 million in 2003. While margins on gas sales improved slightly, this increase was offset by expenses associated with the settlement of a pension obligation and a higher effective tax rate.

TIMBER

Revenues

Timber Operating Revenues

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Log Sales	$22,478	$21,790	$27,341
Green Lumber Sales	7,296	5,923	6,200
Kiln Dry Lumber Sales	29,651	27,416	21,814
Other	1,861	841	871
	$61,286	$55,970	$56,226

Timber Board Feet

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Log Sales	7,601	6,848	8,764
Green Lumber Sales	10,489	9,552	11,913
Kiln Dry Lumber Sales	15,491	15,020	13,300
	33,581	31,420	33,977

2005 Compared with 2004

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

2004 Compared with 2003

Operating revenues for the Timber segment did not change significantly in 2004 as compared with 2003. The decrease in log sales of $5.6 million was principally due to the Company's August 2003 sale of approximately 70,000 acres of timber properties discussed below. However, kiln dry lumber sales increased $5.6 million due to an increase in activity at the Company's mill operations. As a result of the sale of the timber properties, a larger percentage of timber processed in the Company's mills is now purchased from third parties.

Earnings

2005 Compared with 2004

The Timber segment earnings in 2005 were $5.0 million, a decrease of $0.6 million when compared with earnings of $5.6 million in 2004. Increases in the cost of goods sold during 2005 due to a greater amount of timber being harvested on purchased stumpage, which has a higher cost basis than other raw material sources, is primarily responsible for the earnings decline. Also contributing to the decline were overall increases in operating expenses due to higher utility costs. Partially offsetting these declines in earnings were the increased sales of kiln dry lumber and green lumber discussed above, as well as the favorable earnings impact associated with the non-recurrence of a $0.8 million loss recorded in 2004 related to the Company's fiscal 2003 sale of timber properties, as discussed below.

2004 Compared with 2003

The Timber segment earnings in 2004 were $5.6 million, a decrease of $106.9 million when compared with earnings of $112.5 million in 2003. This earnings fluctuation is largely a reflection of the sale of approximately 70,000 acres of timber properties on August 1, 2003 for approximately $186.0 million. As a result of the sale, the Company recorded a gain of $102.2 million in 2003. In 2004, the Company received final timber cruise information of the properties it sold and, based on that information, determined that property records pertaining to $1.3 million of timber property were not properly shown as having been transferred to the purchaser. As a result, the Company removed those assets from its property records and adjusted the previously recognized gain downward by recognizing a loss of $0.8 million. The combination of these two events caused earnings to be lower by $103.0 million. The remainder of the decrease is attributable to lower sales of cherry logs in 2004. While kiln dry lumber sales increased, this benefit was largely offset by an increase in costs associated with purchased timber.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate Operations primarily includes the operations of Horizon LFG, Horizon Power, former International segment activity other than the activity from the Czech Republic operations, and corporate operations. Horizon LFG owns and operates short-distance landfill gas pipeline companies. Horizon Power's activity primarily consists of equity method investments in Seneca Energy, Model City and ESNE. Horizon Power has a 50% ownership interest in each of these entities. The income from these equity method investments is reported as Operations of Unconsolidated Subsidiaries on the Consolidated Statement of Income. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. ESNE generates electricity from an 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. Horizon Power also owns a gas-powered turbine and other assets which it had planned to use in the development of a co-generation plant. The Company is in the process of selling these assets. The former International segment activity primarily consists of project development activities, the largest being projects in Italy and Bulgaria.

Earnings

2005 Compared with 2004

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

2004 Compared with 2003

All Other and Corporate operations experienced a loss of $5.7 million in 2004, an improvement of $2.3 million over a loss of $8.0 million in 2003. This improvement can be attributed primarily to a

$1.4 million increase in the earnings of Horizon LFG and a $1.8 million improvement in the losses experienced by the former International segment.

INTEREST INCOME

Interest income was $4.7 million higher in 2005 compared to 2004. As discussed in the earnings discussion by segment above, the main reason for this increase was the accrual of $3.7 million in interest on a pension related asset in accordance with the New York rate case settlement agreement that was completed in 2005. Interest Income for 2004 did not change significantly from interest income in 2003.

OTHER INCOME

Other income was $9.8 million higher in 2005 compared to 2004. As discussed in the earnings discussion by segment above, the main reasons for this increase included a $2.6 million gain in the Pipeline and Storage segment associated with a FERC approved sale of base gas in 2005 and a $3.9 million gain in the Pipeline and Storage segment associated with insurance proceeds received in prior years for which a contingency was resolved during 2005. Other Income for 2004 did not change significantly from other income in 2003.

INTEREST CHARGES

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

Interest on long-term debt decreased $9.7 million in 2005 and $8.4 million in 2004. The decrease in both years was primarily the result of a lower average amount of long-term debt outstanding.

Other interest charges were $2.3 million higher in 2005 compared to 2004; however, other interest charges were $4.4 million lower in 2004 compared to 2003. The increase in 2005 resulted mainly from $2.1 million of interest expense recorded by the Utility segment as part of an adjustment to a regulatory liability recorded for previous over-collections of New York State gross receipts tax. The decrease in 2004 was primarily the result of lower weighted average interest rates on short-term debt combined with a lower average amount of short-term debt outstanding.

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		
	2005	2004	2003
		(Millions)	
Provided by Operating Activities	$ 317.3	$ 437.1	$ 325.7
Capital Expenditures	(219.5)	(172.3)	(152.2)
Investment in Subsidiaries, Net of Cash Acquired	—	—	(228.8)
Investment in Partnerships	—	—	(0.4)
Net Proceeds from Sale of Foreign Subsidiary	111.6	—	—
Net Proceeds from Sale of Timber Properties	—	—	186.0
Net Proceeds from Sale of Oil and Gas Producing Properties	1.4	7.1	78.5
Other Investing Activities	3.2	2.0	12.1
Short-Term Debt, Net Change	(115.4)	38.6	(147.6)
Long-Term Debt, Net Change	(13.3)	(243.1)	20.7
Issuance of Common Stock	20.3	23.8	17.0
Dividends Paid on Common Stock	(94.1)	(89.1)	(84.5)
Dividends Paid to Minority Interest	(12.7)	—	—
Effect of Exchange Rates on Cash	1.3	3.5	1.6
Net Increase in Cash and Temporary Cash Investments	$ 0.1	$ 7.6	$ 28.1

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for noncash expenses, noncash income and changes in operating assets and liabilities. Noncash items include depreciation, depletion and amortization, impairment of investment in partnership, deferred income taxes, income or loss from unconsolidated subsidiaries net of cash distributions, minority interest in foreign subsidiaries, gain or loss on sale of timber properties, gain or loss on sale of oil and gas producing properties, gain on the sale of discontinued operations, and cumulative effect of changes in accounting.

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 also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment's New York rate jurisdiction by its WNC and in the Pipeline and Storage segment by Supply Corporation's straight fixed-variable rate design.

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

Net cash provided by operating activities totaled $317.3 million in 2005, a decrease of $119.8 million compared with the $437.1 million provided by operating activities in 2004. Much of this decrease can be attributed to higher hedging collateral deposits in the Energy Marketing and Exploration and Production segments. The decrease is also attributable to gas cost recovery timing differences as well as increased working capital requirements in the Utility segment. Partially offsetting this decrease, the Corporate operation experienced a significant cash outflow in January 2004 due to a $23.0 million lump sum payment to a participant of the Company's nonqualified defined benefit plan under a provision of an agreement previously entered into between the Company and the participant. No such cash outflow occurred during 2005.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets from continuing operations totaled $213.6 million in 2005. The table below presents these expenditures:

	Year Ended September 30, 2005 Total Expenditures For Long-Lived Assets (Millions)
Utility	$ 50.1
Pipeline and Storage	21.1
Exploration and Production	122.4
Timber	18.9
All Other and Corporate	1.1
Total Expenditures from Continuing Operations(1)	$213.6

(1) Excludes expenditures from discontinued operations of $5.9 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.

The Company completed a FERC approved sale of base gas from Supply Corporation's jointly-owned Ellisburg Storage Pool in March 2005 for $4.6 million in sales proceeds. As a result of the sale, property, plant, and equipment was reduced by $0.7 million for the cost basis of the gas and a $3.9 million gain before tax on the sale ($2.6 million after tax) was recognized by the Company in 2005. The proceeds of this sale are included in Other Investing Activities on the Consolidated Statement of Cash Flows at September 30, 2005. The gain is included in Other Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities.

Exploration and Production

The Exploration and Production segment's capital expenditures were primarily well drilling and completion expenditures and included approximately $38.5 million for the Canadian region, $41.8 million for the Gulf Coast region ($40.8 million for the off-shore program in the Gulf of Mexico), $29.6 million for the West Coast region and $12.5 million for the Appalachian region. These amounts included approximately $19.2 million spent to develop proved undeveloped reserves.

Timber

The majority of the Timber segment capital expenditures were made for the purchase of land and timber rights in Elk County, Pennsylvania in January 2005. The land and timber, consisting of approximately 12,324 acres, was purchased for approximately $17.6 million. The remaining $1.3 million of capital expenditures in 2005 was made for purchases of equipment for Highland's sawmill and kiln operations.

All Other and Corporate

The majority of the All Other and Corporate capital expenditures were for capital improvements to the Company's corporate headquarters and to the Company's landfill gas pipeline operations.

Estimated Capital Expenditures

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

	Year Ended September 30		
	2006	2007	2008
		(Millions)	
Utility	$ 56.0	$ 56.0	$ 55.0
Pipeline and Storage	34.0	157.0	52.0
Exploration and Production(1)	155.0	110.0	115.0
Timber	2.0	1.0	1.0
All Other and Corporate	2.0	—	—
	$249.0	$324.0	$223.0

(1) Includes estimated expenditures for the years ended September 30, 2006, 2007 and 2008 of approximately $42 million, $22 million and $30 million, respectively, to develop proved undeveloped reserves.

Estimated capital expenditures for the Utility segment in 2006 will be concentrated in the areas of main and service line improvements and replacements and, to a minor extent, the purchase of new equipment.*

Estimated capital expenditures for the Pipeline and Storage segment in 2006 will be concentrated in the reconditioning of storage wells, replacement of storage and transmission lines, and improvements of compressor stations.* The estimated capital expenditures for 2006 also includes $12 million for the Empire Connector project.

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.* Assuming the proposed Millennium Pipeline is constructed, the Empire Connector will provide an upstream supply link for Phase I of the Millennium Pipeline and will transport Canadian and other natural gas supplies to downstream customers, including KeySpan Gas East Corporation, which has entered into precedent agreements to subscribe for at least 150 MDth per day of natural gas transportation service through the Empire State Pipeline and the Millennium Pipeline systems.* The Empire Connector will be designed to move up to approximately 250 MDth of natural gas per day.* Empire anticipates that FERC will provide a determination on this application by November 2006.* The forecasted expenditures for this project over the next three years are as follows: $12.0 million in 2006, $105.0 million in 2007, and $22.0 million in 2008.* These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The targeted in-service date is November 2007.* The Company anticipates financing this project with cash on hand and/or through the use of the Company's bi-lateral lines of credit.* As of September 30, 2005, the Company had incurred approximately $4.0 million in costs (all of which have been reserved) related to this project. Of this amount, $3.4 million and $0.6 million were incurred during the years ended September 30, 2005 and September 30, 2004, respectively.

The Company also plans to extend Supply Corporation's pipeline system from the Tuscarora storage field to the intersection of the proposed Millennium and Empire Connector pipelines (the Tuscarora Extension).* The Tuscarora Extension will be designed initially to move up to approximately 130 MDth of natural gas per day.* The forecasted expenditures for this project over the next three years are as follows: $0 in 2006, $30.0 million in 2007 and $8.0 million in 2008. These expenditures are included as Pipeline and Storage estimated capital expenditures in the table above. The targeted in-service date is late in calendar 2007 or early in calendar 2008.* The Company anticipates financing this project with cash on hand and/or through the use of the Company's bi-lateral lines of credit.* The Tuscarora Extension is contingent on market developments, and the Company has not yet filed an application with the FERC for the authority to build and operate it.

Estimated capital expenditures in 2006 for the Exploration and Production segment include approximately $46.0 million for Canada, $58.0 million for the Gulf Coast region ($54.0 million on the off-shore program in the Gulf of Mexico), $28.0 million for the West Coast region and $23.0 million for the Appalachian region.*

Estimated capital expenditures in the Timber segment will be concentrated on the construction or purchase of new facilities and equipment for this segment's sawmill and kiln operations.*

Estimated capital expenditures in the All Other and Corporate category will be concentrated on the construction of a distributed generation facility at the Company's corporate headquarters.

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, 2005. However, the Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. The Company has SEC authorization under the Holding Company Act to borrow and have outstanding as much as $750.0 million of short-term debt at any time through December 31, 2005. The Company has applied for and expects to receive an extension of this authority through February 8, 2006.* Effective February 8, 2006, the Holding Company Act will be repealed and the Company will no longer need authorization from the SEC thereunder to issue short-term debt. As for bank loans, the Company maintains a number of individual (bi-lateral) uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. Each of these credit lines, which aggregate to $380.0 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.* The total amount available to be issued under the Company's commercial paper program is $200.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million. On August 19, 2005, the Company entered into a new committed credit facility agreement with nine lenders that extends through September 30, 2010. With the committed credit facility agreement in place, the Company plans to increase the size of its commercial paper program from $200.0 million to $300.0 million.*

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, 2005, the Company's debt to capitalization ratio (as calculated under the facility) was .48. The constraints specified in the committed credit facility would permit an additional $1.16 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, 2005, the Company would have been permitted to issue up to a maximum of $696.0 million 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 35%) of the Company's long-term debt (as of September 30, 2005) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $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, 2005, 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, 2005 and September 30, 2004. 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 also has authorization from the SEC, under the Holding Company Act, to issue long-term debt securities and equity securities in an aggregate amount of up to $1.5 billion during the order's authorization period, which commenced in November 2002 and extends through December 31, 2005. The Company has applied for and expects to receive an extension of this authority through February 8, 2006.* Effective February 8, 2006, the Holding Company Act will be repealed and the Company will no longer need Holding Company Act authorization to issue long-term debt securities and equity securities. 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, and within the authorization granted by the SEC under the Holding Company Act. The Company may sell all or a portion of the remaining registered securities if warranted by market conditions and the Company's capital requirements. Any offer and sale of the above mentioned $550.0 million of debt and equity securities will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations thereunder.

The amounts and timing of the issuance and sale of debt or equity securities will depend on market conditions, indenture requirements, regulatory authorizations and the capital requirements of the Company.

On December 8, 2005, the Company's board of directors authorized the Company to implement a share repurchase program, whereby the Company may repurchase outstanding shares of common stock, up to an aggregate amount of 8 million shares in the open market or through privately negotiated transactions. It is expected that this share repurchase program will be funded with cash provided by operating activities and/or through the use of the Company's bi-lateral lines of credit.* The timing of repurchases will depend 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 $52.2 million. These leases have been entered into for the use of buildings, vehicles, construction tools, meters, computer equipment and other items and are accounted for as operating leases. The Company's unconsolidated subsidiaries, which are accounted for under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $9.2 million. The Company has guaranteed 50%, or $4.6 million, of these capital lease commitments.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2005, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2006	2007	2008	2009	2010	Thereafter	Total
				(Millions)			
Long-Term Debt, including interest expense(2)	$ 81.2	$ 80.7	$275.9	$158.9	$51.8	$1,016.6	$1,665.1
Operating Lease Obligations	$ 8.5	$ 7.4	$ 6.6	$ 5.6	$ 4.0	$ 20.1	$ 52.2
Capital Lease Obligations	$ 1.3	$ 0.8	$ 0.9	$ 0.5	$ 0.5	$ 0.6	$ 4.6
Purchase Obligations:							
Gas Purchase Contracts(1)	$997.3	$ 96.1	$ 18.9	$ 7.6	$ 7.4	$ 85.2	$1,212.5
Transportation and Storage Contracts	$138.5	$135.4	$134.6	$133.2	$75.1	$ 7.0	$ 623.8
Other	$ 12.4	$ 8.2	$ 1.7	$ 1.3	$ 1.3	$ 0.9	$ 25.8

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

(2) Refer to Note D — 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.

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the consolidated balance sheet in accordance with the Financial Accounting Standards Board's Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (see Item 7, MD&A under the heading "Critical Accounting Policies — 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

The Company is involved in litigation arising in the normal course of business. Also in the normal course of business, the Company is involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While the resolution of such litigation or regulatory matters could have a material effect on earnings and cash flows in the period of resolution, none of this litigation, and none of these regulatory matters, are expected to change materially the Company's present liquidity position, nor 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 85% of the Company's domestic employees. The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it will continue making contributions to the Retirement Plan.* During 2005, the Company contributed $26.1 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2006 will be in the range of $15.0 million to $20.0 million.* The Company expects that all subsidiaries having domestic employees covered by the Retirement Plan will make contributions to the Retirement Plan.* The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments or through short-term borrowings or through cash from operations.*

The Company provides health care and life insurance benefits for substantially all domestic retired employees under a post-retirement benefit plan (Post-Retirement Plan). The Company has been making contributions to the Post-Retirement Plan over the last several years and anticipates that it will continue making contributions to the Post-Retirement Plan.* During 2005, the Company contributed $39.9 million to the Post-Retirement Plan. The Company anticipates that the annual contribution to the Post-Retirement Plan in 2006 will be in the range of $30.0 million to $40.0 million.* The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.*

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company, in its Exploration and Production segment, Energy Marketing segment, Pipeline and Storage segment, and All Other category, uses various derivative financial instruments (derivatives), including price swap agreements, no cost collars, options and futures contracts, as part of the Company's overall energy commodity price risk management strategy. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from or pay to the respective counterparties at September 30, 2005 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial instruments.

The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in "Inside FERC" or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2005. At September 30, 2005, 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				
	2006	2007	2008	2009	Total
Notional Quantities (Equivalent Bcf)	14.0	2.8	1.7	0.3	18.8
Weighted Average Fixed Rate (per Mcf)	$ 5.77	$ 5.82	$5.40	$5.05	$ 5.73
Weighted Average Variable Rate (per Mcf)	$12.13	$10.66	$9.16	$8.64	$11.60

Crude Oil Price Swap Agreements

	Expected Maturity Dates			
	2006	2007	2008	Total
Notional Quantities (Equivalent bbls)	1,935,000	855,000	45,000	2,835,000
Weighted Average Fixed Rate (per bbl)	$ 34.14	$ 37.03	$ 39.00	$ 35.09
Weighted Average Variable Rate (per bbl)	$ 66.74	$ 65.82	$ 64.20	$ 66.42

At September 30, 2005, the Company would have had to pay its respective counterparties an aggregate of approximately $93.6 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have had to pay an aggregate of approximately $85.6 million to its counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2005.

At September 30, 2004, the Company had natural gas price swap agreements covering 23.0 Bcf at a weighted average fixed rate of $5.47 per Mcf. The Company also had crude oil price swap agreements covering 5,038,000 bbls at a weighted average fixed rate of $32.01 per bbl. The decrease in natural gas price swap agreements from September 2004 to September 2005 is largely attributable to management's decision to utilize more no cost collars as a means of hedging natural gas production in the Exploration and Production segment. The decrease in crude oil price swap agreements is primarily due to the fact that the Company has not been entering into new swap agreements for its West Coast crude oil production. This decision is related to the price, or "basis," differential that exists between the Company's West Coast heavy sour crude oil and the West Texas Intermediate light sweet crude oil that is quoted on the NYMEX. The Company has been unable to hedge against changes in the basis differential.

The following table discloses the notional quantities, the weighted average ceiling price and the weighted average floor price for the no cost collars used by the Company to manage natural gas price risk. The no cost collars provide for the Company to receive monthly payments from (or make payments to) other parties when a variable price falls below an established floor price (the Company receives payment from the counterparty) or exceeds an established ceiling price (the Company pays the counterparty). At September 30, 2005, the Company had not entered into any natural gas or crude oil no cost collars extending beyond 2007.

No Cost Collars

	Expected Maturity Dates		
	2006	2007	Total
Natural Gas			
Notional Quantities (Equivalent Bcf)	6.1	2.4	8.5
Weighted Average Ceiling Price (per Mcf)	$14.37	$18.82	$15.62
Weighted Average Floor Price (per Mcf)	$ 7.57	$ 7.45	$ 7.54

At September 30, 2005, the Company would have had to pay an aggregate of approximately $11.2 million to terminate the natural gas no cost collars outstanding at that date. The Company did not have any outstanding crude oil no cost collars at September 30, 2005.

At September 30, 2004, the Company had natural gas no cost collars covering 5.5 Bcf at a weighted average floor price of $4.93 per Mcf and a weighted average ceiling price of $8.28 per Mcf. The Company also had crude oil no cost collars covering 105,000 bbls at a weighted average floor price of $25.00 per bbl and a weighted average ceiling price of $28.56 per bbl. The increase in natural gas no cost collars from September 2004 to September 2005 is a result of management's decision to utilize more no cost collars as a means of hedging natural gas production in the Exploration and Production segment. No cost collars provide an attractive floor price for the Company's natural gas production while allowing the Company to retain a portion of the upside potential of higher prices.

The following table discloses the notional quantities and weighted average strike prices by expected maturity dates for options used by the Exploration and Production segment to manage natural gas price risk. The put options provide for the Company to receive monthly payments from other parties when a variable price falls below an established floor or "strike" price. The call options provide for the Company to pay monthly payments to other parties when a variable price rises above an established ceiling or "strike" price. At September 30, 2005, the Company held no options with maturity dates extending beyond 2006.

Options

	Expected Maturity Dates	
	2006	Total
Natural Gas Put Options Purchased		
Notional Quantities (Equivalent Bcf)	0.6	0.6
Weighted Average Strike Price (per Mcf)	$5.54	$5.54
Natural Gas Call Options Sold		
Notional Quantities (Equivalent Bcf)	0.6	0.6
Weighted Average Strike Price (per Mcf)	$7.98	$7.98

At September 30, 2005, the Company would have received from the respective counterparties an aggregate of approximately $4 thousand to terminate the put options outstanding at that date. The Company would have had to pay an aggregate of approximately $3.4 million to terminate the call options outstanding at that date.

At September 30, 2004, the Company had natural gas put options covering 1.1 Bcf at an average strike price of $5.99. The Company would have received from the respective counterparties an average of approximately $0.2 million to terminate the put options outstanding at that date. At September 30, 2004, the Company had natural gas call options covering 1.1 Bcf at an average strike price of $8.06. The Company would have had to pay an aggregate of approximately $1.0 million to terminate the call options outstanding at that date.

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, 2005, the Company held no futures contracts with maturity dates extending beyond 2009.

Futures Contracts

	Expected Maturity Dates				
	2006	2007	2008	2009	Total
Net Contract Volumes Purchased (Sold) (Equivalent Bcf)	(2.2)	0.1	(0.1)	— (1)	(2.2)
Weighted Average Contract Price (per Mcf)	$ 8.72	$ 7.12	$6.95	$6.95	$ 8.63
Weighted Average Settlement Price (per Mcf)	$14.71	$11.33	$9.15	$8.14	$14.48

(1) The Energy Marketing segment has sold 2 futures contracts for 2009.

At September 30, 2005, the Company would have had to pay $14.8 million to terminate these futures contracts.

At September 30, 2004, the Company had futures contracts covering 3.8 Bcf (net short position) at a weighted average contract price of $6.17 per Mcf.

The Company may be exposed to credit risk on some of the derivatives disclosed above. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check and then, on an ongoing basis, monitors counterparty credit exposure. Management has obtained guarantees from the parent companies of the respective counterparties to its derivatives. At September 30, 2005, the Company used eight counterparties for its over the counter derivatives. At September 30, 2005, no individual counterparty represented greater than 27% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company's total volumes hedged).

Exchange Rate Risk

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

Interest Rate Risk

The Company's exposure to interest rate risk arises primarily from the $32.1 million of variable rate debt included in Other Notes in the table below. To mitigate this risk, the Company uses an interest rate collar to limit interest rate fluctuations. Under the interest rate collar the Company makes quarterly payments to (or receives payments from) another party when a variable rate falls below an established floor rate (the Company pays the counterparty) or exceeds an established ceiling rate (the Company receives payment from the counterparty). Under the terms of the collar, which extends until 2009, the variable rate is based on LIBOR. The floor rate of the collar is 5.15% and the ceiling rate is 9.375%. The Company would have had to pay $0.5 million to terminate the interest rate collar at September 30, 2005.

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, 2005:

	Principal Amounts by Expected Maturity Dates					
	2006	2007	2008	2009	Thereafter	Total
	(Dollars in millions)					
National Fuel Gas Company						
Long-Term Fixed Rate Debt	$ —	$ —	$200	$100	$796.2	$1,096.2
Weighted Average Interest Rate Paid	—	—	6.3%	6.0%	6.5%	6.4%
Fair Value = $1,149.4 million						
Other Notes						
Long-Term Debt(1)	$9.4	$9.4	$ 9.3	$ 4.1	—	$ 32.2
Weighted Average Interest Rate Paid(2)	4.9%	4.9%	4.9%	4.9%	—	4.9%
Fair Value = $32.2 million						

(1) $32.1 million is variable rate debt.

(2) Weighted average interest rate excludes the impact of an interest rate collar on $32.1 million of variable rate debt.

RATE AND REGULATORY MATTERS

Energy Policy Act

On August 8, 2005, President Bush signed into law the Energy Policy Act, which, among other things, repeals the Holding Company Act effective February 8, 2006. With repeal of the Holding Company Act, the Company will no longer be subject to that act's broad regulatory provisions, including provisions relating to the issuance of securities, sales and acquisitions of securities and utility assets, intra-company transactions and limitations on diversification. The Energy Policy Act, among other things, grants the FERC and state public utility regulatory commissions access to certain books and records of companies in holding company systems, provides (upon request of a state commission or holding company system) for FERC review of allocations of costs of non-power goods and administrative services in electric utility holding company systems, and modifies the jurisdiction of FERC over certain mergers and acquisitions involving public utilities or holding companies. The Company is unable to predict at this time what the ultimate outcome of these or future legislative or regulatory changes will be. The Company is still in the process of analyzing the effect of the Energy Policy Act on the Company, including the effects of any related proceeding at the state level and new regulations at the federal level.

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 filed proposed tariff amendments and supporting testimony designed to increase its annual revenues by $41.3 million beginning October 1, 2004. Parties, including the NYPSC Staff, the New York State Consumer Protection Board, Multiple Intervenors (an advocate for large commercial and industrial customers), natural gas marketers and others, filed responsive testimony recommending a base rate decrease, among other things. Thereafter, the Parties and other interests commenced settlement negotiations. On April 15, 2005, Distribution Corporation, the Parties and others executed an agreement settling all outstanding issues. In an order issued July 22, 2005, the NYPSC, approved the April 15, 2005 settlement agreement, substantially as filed, for an effective date of August 1, 2005. The settlement agreement provides for a rate increase of $21 million by means of the elimination of bill credits ($5.8 million) and an increase in base rates ($15.2 million). For the two-year term of the agreement and thereafter, the return on equity level above which earnings must be shared with rate payers will be 11.5%.

Pennsylvania Jurisdiction

On September 15, 2004, Distribution Corporation filed proposed tariff amendments with PaPUC to increase annual revenues by $22.8 million to cover increases in the cost of service to be effective November 14, 2004. The rate request was filed to address throughput reductions and increased operating costs such as uncollectibles and personnel expenses. Applying standard procedure, the PaPUC suspended Distribution Corporation's tariff filing to perform an investigation and hold hearings. On February 16, 2005, the parties reached a settlement of all issues. The settlement was submitted to the Administrative Law Judge, who, on March 2, 2005 issued a decision recommending adoption of the settlement. The settlement provides for a base rate increase of $12.0 million and terminates the tracking of pension expenses versus the rate allowance. The settlement was approved by PaPUC on March 23, 2005, and the new rates went into effect on April 15, 2005.

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. Management will continue to monitor Supply Corporation's financial position to determine the necessity of filing a rate case in the future.

On November 25, 2003, the FERC issued Order 2004 "Standards of Conduct for Transmission Providers" ("Order 2004"). Order 2004 was clarified in Order 2004-A on April 16, 2004 and Order 2004-B on August 2, 2004. Order 2004, which went into effect September 22, 2004, regulates the conduct of transmission providers (such as Supply Corporation) with their "energy affiliates." The FERC broadened the definition of "energy affiliates" to include any affiliate of a transmission provider if that affiliate engages in or is involved in transmission (gas or electric) transactions, or manages or controls transmission capacity, or buys, sells, trades or administers natural gas or electric energy or engages in financial transactions relating to the sale or transmission of natural gas or electricity. Supply Corporation's principal energy affiliates are Seneca, NFR and, possibly, Distribution Corporation.* Order 2004 provides that companies may request waivers, which the Company has done with respect to Distribution Corporation and is awaiting rulings. Order 2004 also provides an exemption for local distribution companies that are affiliated with interstate pipelines (such as Distribution Corporation), but the exemption is limited, with very minor exceptions, to local distribution corporations that do not make any off-system sales. Distribution Corporation stopped making such off-system sales effective September 22, 2004, although it continues to make certain sales permitted by a prior FERC order; FERC has required Supply Corporation to provide arguments justifying the continued effectiveness of that order. Supply Corporation and Distribution Corporation would like to continue operating as they do, whether by waiver, amendment or further clarification of the new rules, or by complying with the requirements applicable if Distribution Corporation were an energy affiliate. Treating Distribution Corporation as an energy affiliate, without any waivers, would require changes in the way Supply Corporation and Distribution Corporation operate which would decrease efficiency, but probably would not increase capital or operating expenses to an extent that would be material to the financial condition of the Company.* Until there is further clarification from the FERC on the scope of these exemptions and rulings on the Company's waiver requests, the Company is unable to predict the impact Order 2004 will have on the Company. As previously mentioned, Distribution Corporation stopped making off-system sales, effective September 22, 2004. The Company does not expect that change to have a material effect on the Company's results of operations, as margins resulting from off-system sales are minimal as a result of profit sharing with retail customers.*

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

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. The Company has estimated its clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be $3.7 million.* This liability has been recorded on the Consolidated Balance Sheet at September 30, 2005. The Company entered into a transfer agreement for environmental obligations related to a former manufactured gas plant site in New York. Under the terms of the agreement, the Company paid $12.7 million during 2005 to settle its environmental obligations related to this site. The Company also reached a settlement for environmental obligations at another former manufactured gas plant site during 2005, and paid $4.4 million in August 2005 under the terms of the settlement agreement. The Company will continue to be responsible for future ongoing maintenance of the site. The estimated obligation for ongoing maintenance of the site is included in the $3.7 million environmental liability at September 30, 2005. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and insurance proceeds.* Other than discussed in Note G (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 G — Commitments and Contingencies under the heading "Environmental Matters."

NEW ACCOUNTING PRONOUNCEMENTS

In December 2004, the FASB issued SFAS 123R. SFAS 123R replaces SFAS 123 and supercedes APB 25. The Company currently follows APB 25 in accounting for stock-based compensation, as disclosed above. SFAS 123R focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. The Company does not believe that adoption of SFAS 123R will have a material impact on its financial condition and results of operations.* For further discussion of SFAS 123R and its impact on the Company, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

In March 2005, the FASB issued FIN 47, an interpretation of SFAS 143. FIN 47 provides additional guidance on the term "conditional asset retirement obligation" as used in SFAS 143, and in particular the standard clarifies when a Company must record a liability for a conditional asset retirement obligation. The Company is currently evaluating the impact of FIN 47, if any, on its consolidated financial statements. For further discussion of FIN 47 and its impact on the Company, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

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

EFFECTS OF INFLATION

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

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, those which are designated with an asterisk ("*") and those which are identified by the use of the words "anticipates," "estimates," "expects," "intends," "plans," "predicts," "projects," and similar expressions, are "forward-looking" statements as defined in the 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 laws and regulations to which the Company is subject, including changes in tax, environmental, safety and employment laws and regulations, repeal of the Holding Company Act, and changes in laws and regulations relating to repeal of the Holding Company Act;

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

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

4. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment or valuation of derivative financial instruments or the Company's natural gas and oil reserves;
5. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;
6. Changes in the availability and/or price of derivative financial instruments;
7. Changes in the price differentials between various types of oil;
8. Failure of the price differential between heavy sour crude oil and light sweet crude oil to return to its historical norm;
9. Inability to obtain new customers or retain existing ones;
10. Significant changes in competitive factors affecting the Company;
11. Governmental/regulatory actions, initiatives and proceedings, including those involving acquisitions, financings, rate cases (which address, among other things, allowed rates of return, rate design and retained gas), affiliate relationships, industry structure, franchise renewal, and environmental/safety requirements;
12. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;
13. Significant changes from expectations in actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs or plans, including changes in the plans of the sponsors of the proposed Millennium Pipeline to proceed with that project;
14. The nature and projected profitability of pending and potential projects and other investments;
15. Occurrences affecting the Company's ability to obtain funds from operations, debt or equity to finance needed capital expenditures and other investments, including any downgrades in the Company's credit ratings;
16. Uncertainty of oil and gas reserve estimates;
17. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;
18. Ability to successfully identify, drill for and produce economically viable natural gas and oil reserves;
19. Significant changes from expectations in the Company's actual production levels for natural gas or oil;
20. Regarding foreign operations, changes in trade and monetary policies, inflation and exchange rates, taxes, operating conditions, laws and regulations related to foreign operations, and political and governmental changes;
21. Significant changes in tax rates or policies or in rates of inflation or interest;
22. Significant changes in the Company's relationship with its employees or contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur;
23. Changes in accounting principles or the application of such principles to the Company;
24. The cost and effects of legal and administrative claims against the Company;
25. Changes in actuarial assumptions and the return on assets with respect to the Company's retirement plan and post-retirement benefit plans;
26. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide post-retirement benefits; or
27. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

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

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

Item 8 *Financial Statements and Supplementary Data*

Index to Financial Statements

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

Supplementary Data

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have completed an integrated audit of National Fuel Gas Company's fiscal 2005 consolidated financial statements and of its internal control over financial reporting as of September 30, 2005 and audits of its fiscal 2004 and 2003 consolidated financial statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2005 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note A to the consolidated financial statements, the Company adopted Statement of Financial Accounting Standards No. 142, Goodwill and Other Intangible Assets, and No. 143, Accounting for Asset Retirement Obligations, on October 1, 2002.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in "Management's Report on Internal Control Over Financial Reporting" appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of September 30, 2005 based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2005, based on criteria established in *Internal Control — Integrated Framework* issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

PRICEWATERHOUSECOOPERS LLP

Buffalo, New York
December 8, 2005

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2005	2004	2003
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$1,923,549	$1,907,968	$1,921,573
Operating Expenses			
Purchased Gas	959,827	949,452	963,567
Operation and Maintenance	404,517	385,519	361,898
Property, Franchise and Other Taxes	69,076	68,978	79,692
Depreciation, Depletion and Amortization	179,767	174,289	181,329
Impairment of Oil and Gas Producing Properties	—	—	42,774
	1,613,187	1,578,238	1,629,260
Gain (Loss) on Sale of Timber Properties	—	(1,252)	168,787
Gain (Loss) on Sale of Oil and Gas Producing Properties	—	4,645	(58,472)
Operating Income	310,362	333,123	402,628
Other Income (Expense):			
Income from Unconsolidated Subsidiaries	3,362	805	535
Impairment of Investment in Partnership	(4,158)	—	—
Interest Income	6,496	1,771	2,204
Other Income	12,744	2,908	2,427
Interest Expense on Long-Term Debt	(73,244)	(82,989)	(91,381)
Other Interest Expense	(9,069)	(6,763)	(11,196)
Income from Continuing Operations Before Income Taxes	246,493	248,855	305,217
Income Tax Expense	92,978	94,590	124,150
Income from Continuing Operations	153,515	154,265	181,067
Discontinued Operations:			
Income from Operations, Net of Tax	10,199	12,321	6,769
Gain on Disposal, Net of Tax	25,774	—	—
Income from Discontinued Operations	35,973	12,321	6,769
Income Before Cumulative Effect of Changes In Accounting	189,488	166,586	187,836
Cumulative Effect of Changes in Accounting	—	—	(8,892)
Net Income Available for Common Stock	189,488	166,586	178,944
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	718,926	642,690	549,397
	908,414	809,276	728,341
Dividends on Common Stock	95,394	90,350	85,651
Balance at End of Year	$ 813,020	$ 718,926	$ 642,690
Earnings Per Common Share:			
Basic:			
Income from Continuing Operations	$ 1.84	$ 1.88	$ 2.24
Income from Discontinued Operations	0.43	0.15	0.08
Cumulative Effect of Changes in Accounting	—	—	(0.11)
Net Income Available for Common Stock	$ 2.27	$ 2.03	$ 2.21
Diluted:			
Income from Continuing Operations	$ 1.81	$ 1.86	$ 2.23
Income from Discontinued Operations	0.42	0.15	0.08
Cumulative Effect of Changes in Accounting	—	—	(0.11)
Net Income Available for Common Stock	$ 2.23	$ 2.01	$ 2.20
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	83,541,627	82,045,535	80,808,794
Used in Diluted Calculation	85,029,131	82,900,438	81,357,896

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2005	At September 30 2004
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$4,423,255	$4,602,779
Less — Accumulated Depreciation, Depletion and Amortization	1,583,955	1,596,015
	2,839,300	3,006,764
Current Assets		
Cash and Temporary Cash Investments	57,607	57,541
Hedging Collateral Deposits	77,784	8,612
Receivables — Net of Allowance for Uncollectible Accounts of $26,940 and $17,440, Respectively	155,064	129,825
Unbilled Utility Revenue	20,465	18,574
Gas Stored Underground	64,529	68,511
Materials and Supplies — at average cost	33,267	35,516
Unrecovered Purchased Gas Costs	14,817	7,532
Prepayments and Other Current Assets	65,469	35,364
Deferred Income Taxes	83,774	43,105
Fair Value of Derivative Financial Instruments	—	23
	572,776	404,603
Other Assets		
Recoverable Future Taxes	85,000	83,847
Unamortized Debt Expense	17,567	19,573
Other Regulatory Assets	47,028	32,958
Deferred Charges	4,474	3,411
Other Investments	80,394	72,556
Investments in Unconsolidated Subsidiaries	12,658	16,444
Goodwill	5,476	5,476
Intangible Assets	42,302	45,994
Other	15,677	25,977
	310,576	306,236
Total Assets	$3,722,652	$3,717,603
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized — 200,000,000 Shares; Issued and Outstanding — 84,356,748 Shares and 82,990,340 Shares, Respectively	$ 84,357	$ 82,990
Paid In Capital	529,834	506,560
Earnings Reinvested in the Business	813,020	718,926
Total Common Shareholders' Equity Before Items Of Other Comprehensive Loss	1,427,211	1,308,476
Accumulated Other Comprehensive Loss	(197,628)	(54,775)
Total Comprehensive Shareholders' Equity	1,229,583	1,253,701
Long-Term Debt, Net of Current Portion	1,119,012	1,133,317
Total Capitalization	2,348,595	2,387,018
Minority Interest in Foreign Subsidiaries	—	37,048
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	156,800
Current Portion of Long-Term Debt	9,393	14,260
Accounts Payable	155,485	115,979
Amounts Payable to Customers	1,158	3,154
Dividends Payable	24,445	23,210
Other Accruals and Current Liabilities	60,404	46,952
Fair Value of Derivative Financial Instruments	209,072	95,099
	459,957	455,454
Deferred Credits		
Deferred Income Taxes	489,720	501,200
Taxes Refundable to Customers	11,009	11,065
Unamortized Investment Tax Credit	6,796	7,498
Cost of Removal Regulatory Liability	90,396	82,020
Other Regulatory Liabilities	66,339	66,488
Pension and Other Post-Retirement Benefit Liabilities	143,687	70,410
Asset Retirement Obligation	41,411	32,292
Other Deferred Credits	64,742	67,110
	914,100	838,083
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$3,722,652	$3,717,603

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENT OF CASH FLOWS

	Year Ended September 30		
	2005	2004	2003
	(Thousands of dollars)		
Operating Activities			
Net Income Available for Common Stock	$189,488	$166,586	$178,944
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
Gain on Sale of Discontinued Operations	(27,386)	—	—
(Gain) Loss on Sale of Timber Properties	—	1,252	(168,787)
(Gain) Loss on Sale of Oil and Gas Producing Properties	—	(4,645)	58,472
Impairment of Oil and Gas Producing Properties	—	—	42,774
Depreciation, Depletion and Amortization	193,144	189,538	195,226
Deferred Income Taxes	40,388	40,329	78,369
Cumulative Effect of Changes in Accounting	—	—	8,892
(Income) Loss from Unconsolidated Subsidiaries, Net of Cash Distributions	(1,372)	(19)	703
Impairment of Investment in Partnership	4,158	—	—
Minority Interest in Foreign Subsidiaries	2,645	1,933	785
Other	7,390	9,839	11,289
Change in:			
Hedging Collateral Deposits	(69,172)	(7,151)	(1,109)
Receivables and Unbilled Utility Revenue	(31,246)	4,840	(28,382)
Gas Stored Underground and Materials and Supplies	1,934	13,662	(13,826)
Unrecovered Purchased Gas Costs	(7,285)	21,160	(16,261)
Prepayments and Other Current Assets	(30,390)	37,390	(12,628)
Accounts Payable	48,089	(5,134)	13,699
Amounts Payable to Customers	(1,996)	2,462	692
Other Accruals and Current Liabilities	16,085	2,082	9,343
Other Assets	(13,461)	(2,525)	(9,343)
Other Liabilities	(3,667)	(34,450)	(23,124)
Net Cash Provided by Operating Activities	317,346	437,149	325,728
Investing Activities			
Capital Expenditures	(219,530)	(172,341)	(152,251)
Investment in Subsidiaries, Net of Cash Acquired	—	—	(228,814)
Investment in Partnerships	—	—	(375)
Net Proceeds from Sale of Foreign Subsidiary	111,619	—	—
Net Proceeds from Sale of Timber Properties	—	—	186,014
Net Proceeds from Sale of Oil and Gas Producing Properties	1,349	7,162	78,531
Other	3,238	1,974	12,065
Net Cash Used in Investing Activities	(103,324)	(163,205)	(104,830)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	(115,359)	38,600	(147,622)
Net Proceeds from Issuance of Long-Term Debt	—	—	248,513
Reduction of Long-Term Debt	(13,317)	(243,085)	(227,826)
Proceeds from Issuance of Common Stock	20,279	23,763	17,019
Dividends Paid on Common Stock	(94,159)	(89,092)	(84,530)
Dividends Paid to Minority Interest	(12,676)	—	—
Net Cash Used in Financing Activities	(215,232)	(269,814)	(194,446)
Effect of Exchange Rates on Cash	1,276	3,451	1,644
Net Increase in Cash and Temporary Cash Investments	66	7,581	28,096
Cash and Temporary Cash Investments At Beginning of Year	57,541	49,960	21,864
Cash and Temporary Cash Investments At End of Year	$ 57,607	$ 57,541	$ 49,960
Supplemental Disclosure of Cash Flow Information Cash Paid For:			
Interest	$ 84,455	$ 90,705	$104,452
Income Taxes	$ 83,542	$ 30,214	$ 56,146

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2005	2004	2003
	(Thousands of dollars)		
Net Income Available for Common Stock	$189,488	$166,586	$178,944
Other Comprehensive Income (Loss), Before Tax:			
Minimum Pension Liability Adjustment	(83,379)	56,612	(86,170)
Foreign Currency Translation Adjustment	14,286	21,466	54,472
Reclassification Adjustment for Realized Foreign Currency Translation Gain in Net Income	(37,793)	—	(9,607)
Unrealized Gain on Securities Available for Sale Arising During the Period	2,891	3,629	2,419
Reclassification Adjustment for Realized Gains On Securities Available for Sale in Net Income	(651)	—	—
Unrealized Loss on Derivative Financial Instruments Arising During the Period	(206,847)	(129,934)	(47,777)
Reclassification Adjustment for Realized Loss on Derivative Financial Instruments in Net Income	97,689	49,142	69,809
Other Comprehensive Income (Loss), Before Tax:	(213,804)	915	(16,854)
Income Tax Expense (Benefit) Related to Minimum Pension Liability Adjustment	(29,183)	19,814	(30,159)
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	1,012	1,270	847
Reclassification Adjustment for Income Tax Expense on Realized Gains from Securities Available for Sale in Net Income	(228)	—	—
Income Tax Benefit Related to Unrealized Loss on Derivative Financial Instruments Arising During the Period	(79,059)	(49,113)	(18,594)
Reclassification Adjustment for Income Tax Benefit on Realized Loss on Derivative Financial Instruments In Net Income	36,507	18,182	26,953
Income Taxes — Net	(70,951)	(9,847)	(20,953)
Other Comprehensive Income (Loss)	(142,853)	10,762	4,099
Comprehensive Income	$ 46,635	$177,348	$183,043

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A — Summary of Significant Accounting Policies

Principles of Consolidation

The Company consolidates its majority owned subsidiaries. The equity method is used to account for minority owned entities. All significant intercompany balances and transactions are eliminated.

The preparation of the consolidated financial statements in conformity with accounting principles generally accepted in the United States of America 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 accounting principles generally accepted in the United States of America, 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 B — Regulatory Matters for further discussion.

Revenues

The Company's Utility segment records revenue as bills are rendered, except that service supplied but not billed is reported as unbilled utility revenue and is included in operating revenues for the year in which service is furnished. The Company's Pipeline and Storage and Energy Marketing segments record revenue as bills are rendered for service supplied on a calendar month basis. The Company's Timber segment records revenue on lumber and log sales as products are shipped.

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

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 B — Regulatory Matters for further discussion.

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

2.2% warmer than normal results in a surcharge being added to customers' current bills, while weather that is more than 2.2% colder than normal results in a refund being credited to customers' current bills. Since the Utility segment's Pennsylvania rate jurisdiction does not have a WNC, weather variations have a direct impact on the Pennsylvania rate jurisdiction's revenues.

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

Property, Plant and Equipment

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

Oil and gas property acquisition, exploration and development costs are capitalized under the full-cost method of accounting. All costs directly associated with property acquisition, exploration and development activities are capitalized, up to certain specified limits. If capitalized costs exceed these limits at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. The Company's capitalized costs exceeded the full-cost ceiling for the Company's Canadian properties at June 30, 2003 and September 30, 2003. The Company recognized impairments of $31.8 million and $11.0 million at June 30, 2003 and September 30, 2003, respectively.

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

	As of September 30	
	2005	2004(1)
	(Thousands)	
Utility	$1,462,527	$1,426,540
Pipeline and Storage	960,066	946,866
Exploration and Production	1,665,774	1,517,856
Energy Marketing	1,108	1,169
Timber	114,352	97,290
All Other and Corporate	29,275	28,500
	$4,233,102	$4,018,221

(1) On July 18, 2005 the Company completed the sale of its majority interest in U.E., a district heating and electric generation business in the Czech Republic. With this change, the Company has discontinued reporting for an International Segment as explained further in Note 8 — Business Segment Information. U. E.'s depreciable plant at September 30, 2004 was $379,298 and is not included in this table.

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2005	2004	2003
Utility	2.8%	2.8%	2.8%
Pipeline and Storage	4.1%	4.1%	4.4%
Exploration and Production, per Mcfe(2)	$1.74	$1.49	$1.34
Energy Marketing	7.6%	8.7%	10.9%
Timber	6.2%	6.5%	7.0%
All Other and Corporate	4.3%	6.2%	1.8%

(2) 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 $1.72, $1.47 and $1.30 per Mcfe of production in 2005, 2004 and 2003, respectively.

Cumulative Effect of Changes in Accounting

Effective October 1, 2002, the Company adopted SFAS 143. SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. For the Company, this liability represents plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells. When the liability is initially recorded, the entity capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. The cumulative effect of adopting SFAS 143 reduced earnings by $0.6 million, net of income tax. A reconciliation of the Company's asset retirement obligation calculated in accordance with SFAS 143 is shown below ($000s):

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Balance at Beginning of Year	$32,292	$27,493	$36,090
Liabilities Incurred and Revisions of Estimates	8,343	3,510	242
Liabilities Settled	(1,938)	(831)	(13,227)
Accretion Expense	2,448	1,933	2,602
Exchange Rate Impact	266	187	1,786
Balance at End of Year	$41,411	$32,292	$27,493

In the Company's Utility and Pipeline and Storage segment, costs of removal are collected from customers through depreciation expense. 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, 2005 and 2004, the costs of removal reclassified to other regulatory liabilities amounted to $90.4 million and $82.0 million, respectively.

Effective October 1, 2002, the Company adopted SFAS 142. In accordance with SFAS 142, the Company stopped amortization of goodwill and tested it for impairment as of October 1, 2002. The Company's goodwill balance as of October 1, 2002 totaled $8.3 million and was related to the Company's investments in the Czech Republic, which were discontinued in 2005. As a result of the impairment test, the Company recognized an impairment of $8.3 million. In accordance with SFAS 142, this impairment was reported as a cumulative effect of change in accounting. Refer to Note H — Discontinued Operations for further discussion of the Company's sale of its district heating and electric generation business in the Czech Republic.

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 E — 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, options and futures contracts. The Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled fair value of derivative financial instruments. Fair value represents the amount the Company would receive or pay to terminate these instruments.

For effective cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statements of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2004 or 2003. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues or interest expense on the Consolidated Statements of Income. At September 30, 2005, it was determined that certain derivative financial instruments no longer qualified as effective cash flow hedges due to anticipated delays in oil and gas production volumes caused by Hurricane Rita. These volumes were originally forecast to be produced in the first quarter of 2006. As such, at September 30, 2005, the Company reclassified $5.1 million in accumulated losses on such derivative financial instruments from accumulated other comprehensive 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. 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 2005, 2004 or 2003.

Accumulated Other Comprehensive Income (Loss)

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

	Year Ended September 30	
	2005	2004
	(Thousands)	
Minimum Pension Liability Adjustment	$(107,844)	$(53,648)
Cumulative Foreign Currency Translation Adjustment	28,009	51,516
Net Unrealized Loss on Derivative Financial Instruments	(123,339)	(56,733)
Net Unrealized Gain on Securities Available for Sale	5,546	4,090
Accumulated Other Comprehensive Loss	$(197,628)	$(54,775)

At September 30, 2005, it is estimated that $105.8 million of the net unrealized loss on derivative financial instruments shown in the table above will be reclassified into the Consolidated Statement of Income during 2006. As disclosed in Note E — Financial Instruments, the Company's derivative financial instruments extend out to 2009.

Gas Stored Underground — Current

In the Utility segment, gas stored underground — current in the amount of $35.9 million is carried at lower of cost or market, on a last-in, first-out (LIFO) method. Based upon the average price of spot market gas purchased in September 2005, 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 $289.4 million at September 30, 2005. All other gas stored underground — current 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	
	2005	2004
	(Thousands)	
Materials and Supplies	$10,610	$10,550
Other Assets	11,510	8,406
	$22,120	$18,956

Unamortized Debt Expense

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

Foreign Currency Translation

The functional currency for the Company's foreign operations is the local currency of the country where the operations are located. Asset and liability accounts are translated at the rate of exchange on the balance sheet date. Revenues and expenses are translated at the average exchange rate during the period. Foreign currency translation adjustments are recorded as a component of accumulated other comprehensive income (loss).

Income Taxes

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

Consolidated Statement of Cash Flows

For purposes of the Consolidated Statement 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 serve as collateral for open positions on exchange-traded futures contracts, exchange-traded options and over-the-counter swaps and collars.

Prepayments and Other Current Assets

Prepayments and Other Current Assets consists of prepayments in the amounts of $38,323,000 and $28,796,000 at September 30, 2005 and 2004, respectively, as well as federal income taxes receivable in the amounts of $27,146,000 and $6,568,000 at September 30, 2005 and 2004, respectively.

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. The only potentially dilutive securities the Company has outstanding are stock options. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflect the potential dilution as a result of these stock options as determined using the Treasury Stock Method. Stock options that are antidilutive are excluded from the calculation of diluted earnings per common share. There were no stock options excluded as being antidilutive for 2005. For 2004 and 2003, 2,296,828 and 7,789,688 stock options, respectively, were excluded as being antidilutive.

Stock-Based Compensation

The Company, through September 30, 2005, has accounted for stock-based compensation using the intrinsic value method specified by APB 25, and related interpretations. Under that method, no compensation expense was recognized for options granted under the plans for the years ended September 30, 2005, 2004 and 2003. However, in accordance with APB 25, the Company records compensation expense for the market value of restricted stock on the date of award over the periods during which the vesting restrictions exist. Had compensation expense associated with stock options been determined based on fair value at the grant dates, which is the accounting treatment specified by SFAS 123, the Company's net income and earnings per share would have been reduced to the pro forma amounts below:

	Year Ended September 30		
	2005	2004	2003
	(Thousands, except per share amounts)		
Net Income Available for Common Stock As Reported	$189,488	$166,586	$178,944
Add: Stock-Based Compensation Expense Included in Reported Net Income, Net of Tax	336	543	677
Deduct: Stock-Based Compensation Expense Determined Based on Fair Value at the Grant Dates, Net of Tax	(2,782)	(1,861)	(3,782)
Pro Forma Net Income Available for Common Stock	$187,042	$165,268	$175,839
Earnings Per Common Share:			
Basic — As Reported	$ 2.27	$ 2.03	$ 2.21
Basic — Pro Forma	$ 2.24	$ 2.01	$ 2.18
Diluted — As Reported	$ 2.23	$ 2.01	$ 2.20
Diluted — Pro Forma	$ 2.20	$ 1.99	$ 2.16

The weighted average fair value per share of options granted in 2005, 2004 and 2003 was $4.59, $4.66 and $4.17, respectively. These weighted average fair values were estimated on the date of grant using a binomial option pricing model with the following weighted average assumptions:

	Year Ended September 30		
	2005	2004	2003
Quarterly Dividend Yield	1.00%	1.12%	1.10%
Annual Standard Deviation (Volatility)	17.76%	21.77%	22.24%
Risk Free Rate	4.46%	4.61%	3.33%
Expected Term — in Years	7.0	7.0	6.5

New Accounting Pronouncements

In December 2004, the FASB issued SFAS 123R. SFAS 123R replaces SFAS 123 and supercedes APB 25. The Company followed APB 25 in accounting for stock-based compensation through September 30, 2005, as disclosed above. SFAS 123R addresses the accounting for transactions in which an entity exchanges its equity instruments for goods or services. It also addresses transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. This standard focuses primarily on accounting for transactions in which an entity obtains employee services in share-based payment transactions. Under this standard, companies are required to measure the cost of employee services received in exchange for an award of equity instruments based on the fair value of the award at the date of grant. That cost will be recognized over the period during which an employee is required to provide service in exchange for the award. The Company will adopt this standard during the first quarter of 2006. In accordance with SFAS 123R, the Company will use the modified version of prospective application. Under modified prospective application, SFAS 123R applies to new awards and to awards modified, repurchased, or cancelled after the required effective date. Additionally, compensation cost for the portion of awards for which the requisite service has not been rendered that are outstanding as of the required effective date shall be recognized as the requisite service is rendered on or after the required effective date. The compensation cost for that portion of awards shall be based on the grant-date fair value of those awards as calculated for the Company's disclosure under SFAS 123. The Company will not restate any prior periods as a result of adopting SFAS 123R. The Company does not believe that adoption of SFAS 123R will have a material impact on its financial condition and results of operations because substantially all of the Company's options were vested by September 30, 2005.

In March 2005, the FASB issued FIN 47, an interpretation of SFAS 143. FIN 47 provides clarification of the term "conditional asset retirement obligation" as used in SFAS 143, defined as a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the Company. Under this standard, a company must record a liability for a conditional asset retirement obligation if the fair value of the obligation can be reasonably estimated. FIN 47 also serves to clarify when a company would have sufficient information to reasonably estimate the fair value of a conditional asset retirement obligation. FIN 47 becomes effective no later than the end of 2006. The Company is currently evaluating the impact of FIN 47, if any, on its consolidated financial statements.

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

Note B — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2005	2004
	(Thousands)	
Regulatory Assets(1):		
Recoverable Future Taxes (Note C)	$ 85,000	$ 83,847
Unrecovered Purchased Gas Costs (See Regulatory Mechanisms in Note A)	14,817	7,532
Unamortized Debt Expense (Note A)	9,088	9,882
Pension and Post-Retirement Benefit Costs(2) (Note F)	27,135	28,760
Environmental Site Remediation Costs(2) (Note G)	13,054	—
Other(2)	6,839	4,198
Total Regulatory Assets	155,933	134,219
Regulatory Liabilities:		
Cost of Removal Regulatory Liability (See Cumulative Effect Discussion in Note A)	90,396	82,020
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	1,158	3,154
New York Rate Settlements(3)	53,205	50,451
Taxes Refundable to Customers (Note C)	11,009	11,065
Pension and Post-Retirement Benefit Costs(3) (Note F)	12,751	12,051
Other(3)	383	3,986
Total Regulatory Liabilities	168,902	162,727
Net Regulatory Position	$(12,969)	$(28,508)

(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, 2005 and 2004 of $34.3 million and $20.8 million, respectively. Under the terms of its 2005 rate settlement, Distribution Corporation will pass back that regulatory liability to rate payers over a twenty-four month period beginning August 1, 2005. Further, the gross receipts tax surcharge that gave rise to the regulatory liability was eliminated from Distribution Corporation's tariff (New York State income taxes are now recovered as a component of base rates).

Cost Mitigation Reserve ("CMR") — The CMR is a regulatory liability that can be used to offset certain expense items specified in Distribution Corporation's rate settlements. The source of the CMR is principally the accumulation of certain refunds from upstream pipeline companies. During 2005, under the terms of the 2005 rate settlement, Distribution Corporation transferred the remaining balance in a generic restructuring reserve (which had been established in a prior rate settlement) and the balances it had accumulated under various earnings sharing mechanisms to the CMR. The balance in the CMR at September 30, 2005 and 2004 amounted to $7 million and $21.1 million, respectively (note that the 2004 balance includes amounts reclassified in 2005).

Other — The 2005 settlement also established a reserve to fund area development projects, which amounted to $3.8 million at September 30, 2005 (Distribution Corporation established the reserve by transferring the amount from the CMR discussed above). Various other regulatory liabilities have also been created through the New York rate settlements and amounted to $8.1 million and $8.6 million at September 30, 2005 and 2004, respectively.

Note C — 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		
	2005	2004	2003
		(Thousands)	
Operating Expenses:			
Current Income Taxes —			
Federal	$ 40,062	$42,679	$ 37,401
State	14,413	7,871	11,990
Foreign	1,503	206	504
Deferred Income Taxes —			
Federal	27,412	29,559	53,311
State	2,280	9,620	12,983
Foreign	7,308	4,655	7,961
	92,978	94,590	124,150
Other Income:			
Deferred Investment Tax Credit	(697)	(697)	(693)
Discontinued Operations			
Operations	9,310	(1,479)	3,445
Gain on Sale	1,612	—	—
Cumulative Effect of Change in Accounting	—	—	(354)
Total Income Taxes	$103,203	$92,414	$126,548

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

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
U.S.	$223,113	$232,928	$383,695
Foreign	69,578	26,072	(78,202)
	$292,691	$259,000	$305,493

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		
	2005	2004	2003
		(Thousands)	
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$102,442	$90,650	$106,923
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	10,850	11,369	16,232
Foreign Tax Differential	(4,845)	(1,166)	3,318
Foreign Tax Rate Reduction	—	(5,174)	—
Miscellaneous	(5,244)	(3,265)	75
Total Income Taxes	$103,203	$92,414	$126,548

The foreign tax differential amount shown above for 2005 includes tax effects relating to the disposition of a foreign subsidiary. The foreign tax rate reduction amount shown above for 2004 relates to the reduction of the statutory income tax rate in the Czech Republic.

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

	At September 30	
	2005	2004
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$567,850	$568,114
Other	52,436	37,051
Total Deferred Tax Liabilities	620,286	605,165
Deferred Tax Assets:		
Minimum Pension Liability Adjustment	(58,069)	(28,887)
Capital Loss Carryover	(9,145)	(12,546)
Unrealized Hedging Losses	(75,657)	(33,890)
Other	(74,346)	(74,624)
	(217,217)	(149,947)
Valuation Allowance	2,877	2,877
Total Deferred Tax Assets	(214,340)	(147,070)
Total Net Deferred Income Taxes	$405,946	$458,095

	At September 30	
	2005	2004
	(Thousands)	
Presented as Follows:		
Net Deferred Tax Asset — Current	(83,774)	(43,105)
Net Deferred Tax Liability — Non-Current	489,720	501,200
Total Net Deferred Income Taxes	$405,946	$458,095

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 $11.0 million and $11.1 million at September 30, 2005 and 2004, 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 $85.0 million and $83.8 million at September 30, 2005 and 2004, respectively.

In the quarter ended June 30, 2005, the Company recorded a tax liability of $3.8 million relating to a dividend of $72.8 million received from a foreign subsidiary. The tax was recorded at a rate of 5.25% in accordance with the applicable provisions of the American Jobs Creation Act of 2004.

A capital loss carryover of $26.1 million exists at September 30, 2005, which expires if not utilized by September 30, 2008. Although realization is not assured, management estimates that a portion of the deferred tax asset associated with this carryover will be realized during the carryover period, and a valuation allowance is recorded for the remaining portion. Adjustments to the valuation allowance may be necessary in the future if estimates of capital gain income are revised.

Note D — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock		Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
	Shares	Amount			
	(Thousands, except per share amounts)				
Balance at September 30, 2002	80,265	$80,265	$446,832	$549,397	$ (69,636)
Net Income Available for Common Stock				178,944	
Dividends Declared on Common Stock ($1.06 Per Share)				(85,651)	
Other Comprehensive Income, Net of Tax					4,099
Cancellation of Shares	(3)	(3)	(63)		
Common Stock Issued Under Stock and Benefit Plans(1)	1,176	1,176	32,030		
Balance at September 30, 2003	81,438	81,438	478,799	642,690	(65,537)
Net Income Available for Common Stock				166,586	
Dividends Declared on Common Stock ($1.10 Per Share)				(90,350)	
Other Comprehensive Income, Net of Tax					10,762
Common Stock Issued Under Stock and Benefit Plans(1)	1,552	1,552	27,761		
Balance at September 30, 2004	82,990	82,990	506,560	718,926	(54,775)
Net Income Available for Common Stock				189,488	
Dividends Declared on Common Stock ($1.14 Per Share)				(95,394)	
Other Comprehensive Loss, Net of Tax					(142,853)
Cancellation of Shares	(2)	(2)	(52)		
Common Stock Issued Under Stock and Benefit Plans(1)	1,369	1,369	23,326		
Balance at September 30, 2005	84,357	$84,357	$529,834	$813,020(2)	$(197,628)

(1) Paid in Capital includes tax benefits of $3.7 million, $1.5 million and $0.2 million for September 30, 2005, 2004 and 2003, respectively, associated with the exercise of stock options.

(2) 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, 2005, $738.6 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.

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.

Shareholder Rights Plan

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

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

The Rights become exercisable upon the occurrence of a distribution date. At any time following a distribution date, each holder of a Right may exercise its right to receive common stock (or, under certain circumstances, other property of the Company) having a value equal to two times the Purchase Price of the Right then in effect. However, the Rights are subject to redemption or exchange by the Company prior to their exercise as described below.

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

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

At any time prior to the end of the business day on the tenth day following the announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of 10% or more of the total voting power of the Company, the Company may redeem the Rights in whole, but not in part, at a price of $0.005 per Right, payable in cash or stock. A decision to redeem the Rights requires the vote of 75% of the Company's full Board of Directors. Also, at any time following the announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of 10% or more of the total voting power of the Company, 75% of the Company's full Board of Directors may vote to exchange the Rights, in whole or in part, at an exchange rate of one share of common stock, or other property deemed to have the same value, per Right, subject to certain adjustments.

After a distribution date, Rights that are owned by an acquiring person will be null and void. Upon exercise of the Rights, the Company may need additional regulatory approvals to satisfy the requirements of the Rights Agreement. The Rights will expire on July 31, 2008, unless they are exchanged or redeemed earlier than that date.

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

Stock Option and Stock Award Plans

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

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

	Number of Shares Subject to Option	Weighted Average Exercise Price
Outstanding at September 30, 2002	14,629,504	$22.12
Granted in 2003	233,500	$24.61
Exercised in 2003(1)	(673,866)	$16.56
Forfeited in 2003	(123,800)	$23.55
Outstanding at September 30, 2003	14,065,338	$22.41
Granted in 2004	87,000	$24.95
Exercised in 2004(1)	(1,573,794)	$18.29
Forfeited in 2004	(84,633)	$25.42
Outstanding at September 30, 2004	12,493,911	$22.93
Granted in 2005	700,000	$28.19
Exercised in 2005(1)	(2,140,518)	$20.21
Forfeited in 2005	(56,500)	$25.03
Outstanding at September 30, 2005	10,996,893	$23.78
Option shares exercisable at September 30, 2005	10,846,727	$23.78
Option shares exercisable at September 30, 2004	11,594,368	$22.83
Option shares exercisable at September 30, 2003	12,420,444	$22.16
Option shares available for future grant at September 30, 2005(2)	537,634	

(1) In connection with exercising these options, 766,946, 557,410 and 200,708 shares were surrendered and canceled during 2005, 2004 and 2003, respectively.

(2) Including shares available for restricted stock grants.

The following table summarizes information about options outstanding at September 30, 2005:

	Options Outstanding			Options Exercisable	
Range of Exercise Price	Number Outstanding at 9/30/05	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 9/30/05	Weighted Average Exercise Price
$17.14-$19.99	759,422	1.0	$18.38	759,422	$18.38
$20.00-$22.85	3,999,974	3.7	$21.87	3,959,974	$21.88
$22.86-$25.70	3,396,665	5.0	$23.89	3,319,664	$23.89
$25.71-$28.57	2,840,832	6.3	$27.79	2,807,667	$27.80

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.

No awards of restricted stock have been made over the past three years.

As of September 30, 2005, 64,928 shares of non-vested restricted stock were outstanding. Vesting restrictions will lapse as follows: 2006 — 34,600 shares; 2007 — 29,000 shares; and 2010 — 1,328 shares.

Compensation expense related to restricted stock under the Company's stock plans was $0.4 million, $0.7 million and $1.0 million for the years ended September 30, 2005, 2004 and 2003, respectively.

Redeemable Preferred Stock

As of September 30, 2005, 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	
	2005	2004
	(Thousands)	
Medium-Term Notes(1):		
6.0% to 7.50% due May 2008 to June 2025	$ 749,000	$ 749,000
Notes(1):		
5.25% to 6.50% due March 2013 to September 2022(2)	347,222	347,272
	1,096,222	1,096,272
Other Notes:		
Secured(3)	32,100	41,433
Unsecured	83	9,872
Total Long-Term Debt	1,128,405	1,147,577
Less Current Portion	9,393	14,260
	$1,119,012	$1,133,317

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

(2) At September 30, 2005 and 2004, $97,222,000 and $97,272,000, respectively, of these notes were callable at par at any time after September 15, 2006. The change in the amount outstanding from year to year is attributable to the estates of individual note holders exercising put options due to the death of an individual note holder.

(3) These notes constitute "project financing" and are secured by the various project documentation and natural gas transportation contracts related to the Empire State Pipeline. The interest rate on these notes is a variable rate based on LIBOR.

As of September 30, 2005, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $9.4 million in 2006, $9.4 million in 2007, $209.3 million in 2008, $104.1 million in 2009, zero in 2010, and $796.2 million thereafter.

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. As for the former, the Company maintains a number of individual (bi-lateral) uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. Each of these credit lines, which aggregate to $380.0 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. The total amount available to be issued under the Company's commercial paper program is $200.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million, which is committed to the Company through September 30, 2010.

At September 30, 2005, the Company had no outstanding short-term notes payable to banks or commercial paper. At September 30, 2004, the Company had outstanding notes payable to banks and commercial paper of $26.5 million and $130.3 million, respectively. All of this debt was domestic.

The weighted average interest rate on notes payable to banks was 1.82% at September 30, 2004. The weighted average interest rate on commercial paper was 1.85% at September 30, 2004.

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, 2005, the Company's debt to capitalization ratio (as calculated under the facility) was .48. The constraints specified in the committed credit facility would permit an additional $1.16 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, 2005, the Company would have been permitted to issue up to a maximum of $696.0 million 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 35%) of the Company's long-term debt (as of September 30, 2005) was issued contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest or any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company's $300.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $20.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2005, the Company had no debt outstanding under the committed credit facility.

Note E — 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			
	2005 Carrying Amount	2005 Fair Value	2004 Carrying Amount	2004 Fair Value
	(Thousands)			
Long-Term Debt	$1,128,405	$1,181,599	$1,147,577	$1,199,189

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 $59.6 million and $56.1 million at September 30, 2005 and 2004, 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 equity mutual fund purchased in 2005 was $9.8 million at September 30, 2005 and the gross unrealized gain on this equity mutual fund was $0.4 million at September 30, 2005. The fair value of the equity mutual fund sold during 2005 was $7.8 million at September 30, 2004 and the gross unrealized gain on this equity mutual fund was $0.1 million at September 30, 2004. The fair value of the stock of an insurance company was $10.5 million and $8.7 million at September 30, 2005 and 2004, respectively. The gross unrealized gain on this stock was $8.1 million and $6.2 million at September 30, 2005 and 2004, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

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

Under the price swap agreements, the Company receives monthly payments from (or makes payments to) other parties based upon the difference between a fixed price and a variable price as specified by the agreement. The variable price is either a crude oil or natural gas price quoted on the New York Mercantile Exchange (NYMEX) or a quoted natural gas price in "Inside FERC." The majority of these derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment and the All Other category. The Energy Marketing segment accounts for these derivative financial instruments as fair value hedges and uses them to hedge against falling prices, a risk to which they are 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, 2005, the Company had natural gas price swap agreements covering a notional amount of 18.8 Bcf extending through 2009 at a weighted average fixed rate of $5.73 per Mcf. Of this amount, 4.3 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $5.12 per Mcf. The remaining 14.5 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $5.91 per Mcf. The Company also had crude oil price swap agreements covering a notional amount of 2,835,000 bbls extending through 2008 at a weighted average fixed rate of $35.09 per bbl. At September 30, 2005, the Company would have had to pay a net $179.2 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 "Inside FERC." These derivative financial instruments are accounted for as cash flow hedges and are used to lock in a price range for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment. At September 30, 2005, the Company had no cost collars on natural gas covering a notional amount of 8.5 Bcf extending through 2007 with a weighted average floor price of $7.54 per Mcf and a weighted average ceiling price of $15.62 per Mcf. The Company did not have any outstanding no cost collars on crude oil at September 30, 2005. At September 30, 2005, the Company would have had to pay $11.2 million to terminate the no cost collars.

At September 30, 2005, the Company, in the Exploration and Production segment, had purchased natural gas put options and sold natural gas call options extending through 2006. The call options sold by the Company cover a notional amount of 0.6 Bcf at a weighted average strike price of $7.98 per Mcf. The put options purchased by the Company cover a notional amount of 0.6 Bcf at a weighted average strike price of $5.54 per Mcf. These derivative financial instruments are accounted for as cash flow hedges. The call options are used to establish a ceiling price (the Company makes payments to the counterparty when a variable price rises above the ceiling price) for the anticipated sale of natural gas in the Exploration and Production segment. At September 30, 2005, the Company would have had to pay $3.4 million to terminate these call options. The put options are used to establish a floor price (the Company receives payment from the counterparty when a variable price falls below the floor price) for the anticipated sale of natural gas in the Exploration and Production segment. At September 30, 2005, the Company would have received $4 thousand to terminate these put options.

At September 30, 2005, the Company had long (purchased) futures contracts covering 1.2 Bcf of gas extending through 2007 at a weighted average contract price of $9.12 per Mcf. They are accounted for as fair value hedges and are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with commercial and industrial customers. The Company would have received $6.0 million to terminate these futures contracts at September 30, 2005.

At September 30, 2005, the Company had short (sold) futures contracts covering 3.4 Bcf of gas extending through 2009 at a weighted average contract price of $8.44 per Mcf. Of this amount, 2.3 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 1.1 Bcf is accounted for as fair value hedges. The Company would have had to pay $20.8 million to terminate these futures contracts at September 30, 2005.

The Company may be exposed to credit risk on some of the derivative financial instruments discussed above. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on an ongoing basis monitors counterparty credit exposure. Management has obtained guarantees from the parent companies of the respective counterparties to its derivative financial instruments. At September 30, 2005, the Company used eight counterparties for its over the counter derivative financial instruments. At September 30, 2005, no individual counterparty represented greater than 27% of total credit risk (measured as volumes hedged by an individual counterparty as a percentage of the Company's total volumes hedged).

The Company uses an interest rate collar to limit interest rate fluctuations on certain variable rate debt in the Pipeline and Storage segment. Under the interest rate collar the Company makes quarterly payments (or receives payments from) another party when a variable rate falls below an established floor rate (the Company pays the counterparty) or exceeds an established ceiling rate (the Company receives payment from the counterparty). Under the terms of the collar, which extends until 2009, the variable rate is based on LIBOR. The floor rate of the collar is 5.15% and the ceiling rate is 9.375%. At September 30, 2005 the notional amount on the collar was $35.0 million. The Company would have had to pay $0.5 million to terminate the interest rate collar at September 30, 2005.

Note F — Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan) that covers approximately 85% of the domestic employees of the Company. The Company provides health care and life insurance benefits for substantially all domestic retired employees under a post-retirement benefit plan (Post-Retirement Plan).

The Company's policy is to fund the Retirement Plan with at least an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. The Company has established Voluntary Employees' Beneficiary Association (VEBA) trusts for its Post-Retirement Plan. Contributions to the VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code and regulations and are made to fund employees' post-retirement health care and life insurance benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its Post-Retirement Plan. They are separate accounts within the Retirement Plan used to pay retiree medical benefits for the associated participants in the Retirement Plan. Contributions are tax-deductible when made and investments accumulate tax-free. Retirement Plan and Post-Retirement Plan assets primarily consist of equity and fixed income investments or units in commingled funds or money market funds.

The expected returns on plan assets of the Retirement Plan and Post-Retirement Plan are applied to the market-related value of plan assets of the respective plans. For the Retirement Plan, the market-related value of assets recognizes the performance of its portfolio over five years and reduces the effects of short-term market fluctuations. The market-related value of Post-Retirement Plan assets is set equal to market value.

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, 2005, 2004 and 2003, respectively.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2005	2004	2003	2005	2004	2003
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 693,532	$ 694,960	$ 625,470	$ 422,003	$ 467,418	$ 393,851
Service Cost	13,714	14,598	13,043	6,153	6,027	5,844
Interest Cost	42,079	40,565	40,967	25,783	26,393	26,124
Plan Participants' Contributions	—	—	—	1,017	627	682
Actuarial (Gain) Loss	115,128	(19,593)	51,302	110,663	(62,146)	57,983
Benefits Paid	(39,249)	(36,998)	(35,822)	(19,346)	(16,316)	(17,066)
Benefit Obligation at End of Period	$ 825,204	$ 693,532	$ 694,960	$ 546,273	$ 422,003	$ 467,418
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 573,366	$ 491,333	$ 485,927	$ 229,484	$ 166,494	$ 150,293
Actual Return on Plan Assets	56,201	81,946	6,145	20,578	38,960	390
Employer Contribution	26,144	37,085	35,083	39,903	39,720	32,195
Plan Participants' Contributions	—	—	—	1,017	627	682
Benefits Paid	(39,249)	(36,998)	(35,822)	(19,346)	(16,316)	(17,066)
Fair Value of Assets at End of Period	$ 616,462	$ 573,366	$ 491,333	$ 271,636	$ 229,485	$ 166,494
Reconciliation of Funded Status						
Funded Status	$(208,742)	$(120,166)	$(203,627)	$(274,637)	$(192,518)	$(300,924)
Unrecognized Net Actuarial Loss	257,553	159,554	222,250	205,423	108,943	212,242
Unrecognized Transition Obligation	—	—	—	57,017	64,144	71,272
Unrecognized Prior Service Cost	8,142	9,171	10,274	17	20	26
Net Amount Recognized at End of Period	$ 56,953	$ 48,559	$ 28,897	$ (12,180)	$ (19,411)	$ (17,384)

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2005	2004	2003	2005	2004	2003
	(Thousands)					
Amounts Recognized in the Balance Sheets Consist of:						
Accrued Benefit Liability	$(117,103)	$ (43,147)	$(120,524)	$ (26,584)	$ (27,263)	$ (23,163)
Prepaid Benefit Cost	—	—	—	14,404	7,852	5,779
Intangible Assets	8,142	9,171	10,274	—	—	—
Accumulated Other Comprehensive Loss (Pre-Tax)	165,914	82,535	139,147	—	—	—
Net Amount Recognized at End of Period	$ 56,953	$ 48,559	$ 28,897	$ (12,180)	$ (19,411)	$ (17,384)
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	5.00%	6.25%	6.00%	5.00%	6.25%*	6.00%
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	$ 13,714	$ 14,598	$ 13,043	$ 6,153	$ 6,027	$ 5,844
Interest Cost	42,079	40,565	40,967	25,783	26,393	26,124
Expected Return on Plan Assets	(49,545)	(48,281)	(47,260)	(18,862)	(14,898)	(12,268)
Amortization of Prior Service Cost	1,029	1,103	1,176	4	4	4
Amortization of Transition Amount	—	—	(3,716)	7,127	7,127	7,127
Recognition of Actuarial (Gain) or Loss	10,473	9,438	2,231	12,467	17,092	14,866
Net Amortization and Deferral for Regulatory Purposes	1,988	722	3,781	(410)	(9,731)	(15,423)
Net Periodic Benefit Cost	$ 19,738	$ 18,145	$ 10,222	$ 32,262	$ 32,014	$ 26,274
Other Comprehensive (Income) Loss (Pre-Tax) Attributable to Change In Additional Minimum Liability Recognition	$ 83,379	$ (56,612)	$ 86,170	$ —	$ —	$ —
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	6.25%	6.00%	6.75%	6.25%	6.25%*	6.75%
Expected Return on Plan Assets	8.25%	8.25%	8.50%	8.25%	8.25%	8.50%
Rate of Compensation Increase	5.00%	5.00%	5.00%	5.00%	5.00%	5.00%

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

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

In accordance with the provisions of SFAS 87, the Company recorded an additional minimum liability at September 30, 2005, 2004 and 2003 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, has offset the additional liability to the extent of previously Unrecognized Prior Service Cost. The amount in excess of Unrecognized Prior Service Cost is recorded net of the related tax benefit as accumulated other comprehensive loss. The pre-tax amount of the accumulated other comprehensive loss is shown in the table above. The projected benefit obligation, accumulated benefit obligation and fair value of assets for the retirement plan were as follows:

	2005	2004	2003
Projected Benefit Obligation	$825,204	$693,532	$694,960
Accumulated Benefit Obligation	$733,565	$616,513	$611,858
Fair Value of Plan Assets	$616,462	$573,366	$491,333

The effect of the discount rate change for the Retirement Plan in 2005, was to increase the Benefit Obligation by $113.0 million. The discount rate change for the Retirement Plan in 2004 caused the Benefit Obligation to decrease by $20.2 million. The effect of the discount rate change in 2003 was to increase the Benefit Obligation of the Retirement Plan by $57.4 million.

The Company made cash contributions totaling $26.1 million to the Retirement Plan during the year ended September 30, 2005. The Company expects that the annual contribution to the Retirement Plan in 2006 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: $42.5 million in 2006; $43.7 million in 2007; $45.1 million in 2008; $46.8 million in 2009; $48.6 million in 2010; and $271.2 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 insignificant through September 30, 2005. Costs associated with the Company's contributions to the Tax-Deferred Savings Plans were $4.2 million, $4.2 million, and $4.3 million for the years ended September 30, 2005, 2004 and 2003, 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 $4.3 million, $13.7 million and $5.1 million in 2005, 2004 and 2003, respectively. The accumulated benefit obligation for this plan was $25.2 million and $18.2 million at September 30, 2005 and 2004, respectively. The projected benefit obligation for the plan was $47.6 million and $35.7 million at September 30, 2005 and 2004, respectively. The actuarial valuations for this plan were determined based on a discount rate of 5.0%, 6.25% and 6.0% as of September 30, 2005, 2004 and 2003, respectively; a rate of compensation increase of 10.0% as of September 30, 2005 and September 30, 2004, and 8.11% as of September 30, 2003; and an expected long-term rate of return on plan assets of 8.25%, at September 30, 2005, 2004 and 2003.

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

The effect of the discount rate change in 2005 was to increase the Other Post-Retirement Benefit Obligation by $78.2 million. Effective July 1, 2005, the Medicare Part B reimbursement trend, prescription drug trend and medical trend assumptions were changed. The effect of these assumption changes was to increase the other post-retirement benefit obligation by $21.7 million. Also effective July 1, 2005, the percent of active female participants who are assumed to be married at retirement was changed. The effect of this assumption change was to decrease the other post-retirement benefit obligation by $6.9 million. Other actuarial experience increased the Other Post-Retirement Benefit Obligation in 2005 by $17.9 million.

On December 8, 2003, the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the Act) was signed into law. This Act introduces a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. In accordance with FASB Staff Position FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003", since the Company is assumed to continue to provide a prescription drug benefit to retirees in the point of service and indemnity plans that is at least actuarially equivalent to Medicare Part D, the impact of the Act was reflected as of December 8, 2003. The discount rate was changed from 6.0% to 6.25% per annum as of the remeasurement date, which resulted in a decrease in the benefit obligation of $15.9 million in 2004. The Other Post-Retirement Benefit Obligation decreased by $42.9 million and the Net Periodic Post-Retirement Benefit Cost decreased by $4.2 million as a result of the Act for 2004. Effective July 1, 2004, the Medicare B Reimbursement trend assumption was changed. The effect of this change was to decrease the Other Post-Retirement Benefit Obligation by $3.5 million for 2004.

The effect of the discount rate change in 2003 was to increase the Other Post-Retirement Benefit Obligation by $45.1 million. The prescription drug aging assumptions and related factors were changed in 2003 to better reflect anticipated future experience. The effect of the changed prescription drug assumptions was to decrease the Other Post-Retirement Benefit Obligation by $22.6 million. Other actuarial experience increased the Other Post-Retirement Benefit Obligation in 2003 by $35.4 million.

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

	Benefit Payments	Subsidy Receipts
First Year	$ 20,987,000	$ (604,000)
Second Year	$ 23,383,000	$ (1,398,000)
Third Year	$ 25,438,000	$ (1,620,000)
Fourth Year	$ 27,597,000	$ (1,847,000)
Fifth Year	$ 29,901,000	$ (2,058,000)
Next Five Years	$177,401,000	$(13,634,000)

The annual rate of increase in the per capita cost of covered medical care benefits for both Pre and Post age 65 participants was assumed to be 11.0% for 2003 and 10.0% for 2004. In 2005, the Company began making separate estimates of the annual rate of increase in the per capita cost of covered medical care benefits for Pre and Post age 65 participants. The rate of increase for Pre age 65 participants was 10% and was assumed to gradually decline to 5.0% by the year 2014. The rate of increase for the Post age 65 participants was 7.5% 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 13.5% for 2003, 12.0% for 2004, 12.5% for 2005, 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 7.0% for 2003, 9.25% for 2004, and 6.0% for 2005. The annual rate of increase for the Medicare Part B Reimbursement is expected to fluctuate between 0% and 7.5% over the next 10 years and reach 5.0% by 2016.

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the Other Post-Retirement Benefit Obligation as of October 1, 2005 would be increased by $80.2 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 2005 by $5.1 million. If the health care cost trend rates were decreased by 1% in each year, the Other Post-Retirement Benefit Obligation as of October 1, 2005 would be decreased by $65.4 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2005 by $4.1 million.

The Company made cash contributions totaling $39.9 million to the Other Post-Retirement Benefit Plan during the year ended September 30, 2005. The Company expects that the annual contribution to the Other Post-Retirement Benefit Plan in 2006 will be in the range of $30.0 million to $40.0 million.

The Company's Retirement Plan weighted average asset allocations at September 30, 2005, 2004 and 2003 by asset category are as follows:

Asset Category	Target Allocation 2006	Percentage of Plan Assets at September 30		
		2005	2004	2003
Equity Securities	60-70%	63%	61%	53%
Fixed Income Securities	25-35%	28%	28%	32%
Other	5-15%	9%	11%	15%
Total		100%	100%	100%

The Company's Post-Retirement Plan weighted average asset allocations at September 30, 2005, 2004 and 2003 by asset category are as follows:

Asset Category	Target Allocation 2006	Percentage of Plan Assets at September 30		
		2005	2004	2003
Equity Securities	85-95%	92%	91%	85%
Fixed Income Securities	0-10%	2%	1%	1%
Other	0-10%	6%	8%	14%
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 Executive Retirement Plan, and the Other Post-Retirement Benefit Plan is 5.0% as of September 30,

2005. 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 reasonably matches the expected timing of anticipated future benefit payments.

Note G — Commitments and Contingencies

Environmental Matters

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

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. The Company has estimated its remaining clean-up costs related to the sites described below in paragraphs (i) and (ii) will be $3.7 million. This liability has been recorded on the Consolidated Balance Sheet at September 30, 2005. Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, adverse changes in environmental regulations, new information or other factors could impact the Company.

(i) Former Manufactured Gas Plant Sites

The Company has incurred or is incurring clean-up costs at five former manufactured gas plant sites in New York and Pennsylvania. The Company reached a settlement for environmental obligations at one site during the year, and paid $4.4 million in August 2005 under the terms of the settlement agreement. The Company will continue to be responsible for future ongoing maintenance of the site. The estimated obligation for ongoing maintenance of the site is included in the $3.7 million environmental liability at September 30, 2005. At a second site in New York, the Company entered into a transfer agreement for environmental obligations at the site. Under the terms of the agreement, the Company paid $12.7 million during the year to settle its environmental obligations related to this site. At a third site, remediation is complete and long-term maintenance and monitoring activities are ongoing. A fourth site, which allegedly contains, among other things, manufactured gas plant waste, is in the investigation stage. Remediation has been completed at a fifth site; however, post-remedial construction care and maintenance is ongoing.

With regard to the payments made to settle environmental obligations for the two former manufactured gas plant sites discussed above, the Company expects to recover these clean-up costs from a combination of rate recovery and insurance proceeds.

(ii) Third Party Waste Disposal Sites

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

(iii) Other

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

Other

The Company, in its Utility segment, Energy Marketing segment, and All Other category, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. Substantially all of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $1.1 billion in 2006, $0.2 billion in 2007, $0.2 billion in 2008, $0.1 billion in 2009, $0.1 billion in 2010, and $0.1 billion thereafter. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of buildings, vehicles, construction tools, meters, computer equipment and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $8.5 million in 2006, $7.4 million in 2007, $6.6 million in 2008, $5.6 million in 2009, $4.0 million in 2010, and $20.1 million thereafter.

The Company is involved in litigation arising in the normal course of its business. In addition to the regulatory matters discussed in Note B — Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business that involve rate base, cost of service and purchased gas cost issues. While the resolution of such litigation or other regulatory matters could have a material effect on earnings and cash flows in the year of resolution, none of this litigation, and none of these other regulatory matters, are currently expected to have a material adverse effect on the financial condition of the Company.

Note H — Discontinued Operations

On July 18, 2005, the Company completed the sale of its entire 85.16% interest in U.E., a district heating and electric generation business in the Bohemia region of the Czech Republic, to Czech Energy Holdings, a.s. for sales proceeds of approximately $116.3 million. The sale resulted in the recognition of a gain of approximately $25.8 million, net of tax, at September 30, 2005. Current market conditions, 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 has presented the Czech Republic operations, which are primarily comprised of U.E., as discontinued operations. U.E. was the major component of the Company's International segment. With this change in presentation, the Company has discontinued all reporting for an International segment, as explained further in Note I — Business Segment Information.

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

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Operating Revenues	$124,840	$123,425	$113,898
Operating Expenses	103,155	112,178	102,110
Operating Income	21,685	11,247	11,788
Other Income	2,048	1,992	2,256
Interest Expense	(558)	(838)	(2,479)
Income before Income Taxes and Minority Interest	23,175	12,401	11,565
Income Tax Expense	10,331	(1,853)	4,011
Minority Interest, Net of Taxes	2,645	1,933	785
Income from Discontinued Operations	10,199	12,321	6,769
Gain on Disposal, Net of Taxes of $1,612	25,774	—	—
Income from Discontinued Operations	$ 35,973	$ 12,321	$ 6,769

Note I — 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, an intrastate pipeline which was acquired on February 6, 2003 (see Note K — Acquisitions). 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, in the Gulf Coast region of Texas, Louisiana and Alabama and in the provinces of Alberta, Saskatchewan and British Columbia in Canada. Seneca's production is, for the most part, sold to purchasers located in the vicinity of its wells. On September 30, 2003, Seneca sold its southeast Saskatchewan oil and gas properties for a loss of $58.5 million, as shown in the table below for the year ended September 30, 2003. Proved reserves associated with the properties sold were 19.4 million barrels of oil and 0.3 Bcf of natural gas. When the transaction closed, the initial proceeds received were subject to an adjustment based on working capital and the resolution of certain income tax matters. In 2004, those items were resolved with the buyer and, as a result, the Company received an additional $4.6 million of sales proceeds.

The Energy Marketing segment is comprised of NFR's operations. NFR markets natural gas to industrial, commercial, public authority and residential end-users in western and central New York and northwestern Pennsylvania, offering competitively priced energy and energy management services for its customers.

The Timber segment's operations are carried out by the Northeast division of Seneca and by Highland. This segment has timber holdings (primarily high quality hardwoods) in the northeastern United States and sawmills and kilns in Pennsylvania. On August 1, 2003, the Company sold approximately 70,000 acres of timber property in Pennsylvania and New York. A gain of $168.8 million was recognized on the sale of this timber property, as shown in the table below for the year ended September 30, 2003. During 2004, the Company received final timber cruise information of the properties it sold and, based on that information, determined that property records pertaining to $1.3 million of timber property were not properly shown as having been transferred to the purchaser. As a result, the Company removed those assets from its property records and adjusted the previously recognized gain downward by recognizing a pretax loss of $1.3 million.

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 H — 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 has discontinued all reporting for an International segment and previous period segment information has been restated to reflect this change. All Czech Republic operations have been reported as discontinued operations. Any remaining international activity has been included in corporate operations.

	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	$ 293,425	$329,714	$ 61,285	$1,918,801	$ 4,748	$ —	$1,923,549
Intersegment Revenues	$ 15,495	$ 83,054	$ —	$ —	$ 1	$ 98,550	$ 8,606	$(107,156)	$ —
Interest Income	$ 4,111	$ 76	$ 4,661	$ 783	$ 438	$ 10,069	$ 19	$ (3,592)	$ 6,496
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	$ 90,912	$ 41	$ 6,601	$ 175,763	$ 3,537	$ 467	$ 179,767
Income Tax Expense	$ 23,102	$ 39,068	$ 28,353	$ 3,210	$ 2,271	$ 96,004	$ (1,425)	$ (1,601)	$ 92,978
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	$ 50,659	$ 5,077	$ 5,032	$ 160,419	$ (2,616)	$ (4,288)	$ 153,515
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 50,071	$ 21,099	$ 122,450	$ 58	$ 18,894	$ 212,572	$ 463	$ 618	$ 213,653
	At September 30, 2005								
	(Thousands)								
Segment Assets	$1,394,019	$789,704	$1,211,081	$ 91,999	$161,648	$3,648,451	$72,839	$ 1,362	$3,722,652

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

	Year Ended September 30, 2004								
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)								
Revenue from External Customers	$1,137,288	$122,970	$ 293,698	$284,349	$55,968	$1,894,273	$13,695	$ —	$1,907,968
Intersegment Revenues	$ 15,353	$ 86,737	$ —	$ —	$ 2	$ 102,092	$ —	$(102,092)	$ —
Interest Income	$ 552	$ 217	$ 1,831	$ 521	$ 312	$ 3,433	$ 15	$ (1,677)	$ 1,771
Interest Expense	$ 21,945	$ 10,933	$ 50,642	$ 33	$ 2,218	$ 85,771	$ 919	$ 3,062	$ 89,752
Depreciation, Depletion and Amortization	$ 39,101	$ 37,345	$ 89,943	$ 102	$ 6,277	$ 172,768	$ 1,071	$ 450	$ 174,289
Income Tax Expense	$ 31,393	$ 30,968	$ 28,899	$ 3,964	$ 3,320	$ 98,544	$ 829	$ (4,783)	$ 94,590
Income from Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ —	$ 805	$ —	$ 805
Significant Item: Loss on Sale of Timber Properties	$ —	$ —	$ —	$ —	$ 1,252	$ 1,252	$ —	$ —	$ 1,252
Significant Item: Gain on Sale of Oil and Gas Producing Properties	$ —	$ —	$ 4,645	$ —	$ —	$ 4,645	$ —	$ —	$ 4,645
Segment Profit (Loss): Income (Loss) from Continuing Operations	$ 46,718	$ 47,726	$ 54,344	$ 5,535	$ 5,637	$ 159,960	$ 1,530	$ (7,225)	$ 154,265
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 55,449	$ 23,196	$ 77,654	$ 10	$ 2,823	$ 159,132	$ 200	$ 5,511	$ 164,843
	At September 30, 2004								
	(Thousands)								
Segment Assets	$1,355,964	$783,145	$1,078,217	$68,599	$140,992	$3,426,917	$77,013	$ 213,673(1)	$3,717,603

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

	Year Ended September 30, 2003								
	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	$1,145,336	$106,499	$ 305,314	$304,660	$ 56,226	$1,918,035	$ 3,366	$ 172	$1,921,573
Intersegment Revenues	$ 17,647	$ 94,921	$ —	$ —	$ —	$ 112,568	$ —	$(112,568)	$ —
Interest Income	$ 1,630	$ 77	$ 1,119	$ 692	$ 319	$ 3,837	$ 25	$ (1,658)	$ 2,204
Interest Expense	$ 29,122	$ 14,000	$ 53,326	$ 33	$ 2,507	$ 98,988	$ 521	$ 3,068	$ 102,577
Depreciation, Depletion and Amortization	$ 38,186	$ 35,940	$ 99,292	$ 117	$ 7,543	$ 181,078	$ 238	$ 13	$ 181,329
Income Tax Expense	$ 36,857	$ 30,863	$ (17,537)	$ 3,350	$ 72,692	$ 126,225	$ 279	$ (2,354)	$ 124,150
Income from Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ —	$ 535	$ —	$ 535
Significant Item: Gain on Sale of Timber Properties	$ —	$ —	$ —	$ —	$168,787	$ 168,787	$ —	$ —	$ 168,787
Significant Item: Loss on Sale of Oil and Gas Producing Properties	$ —	$ —	$ 58,472	$ —	$ —	$ 58,472	$ —	$ —	$ 58,472
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	$ —	$ —	$ 42,774	$ —	$ —	$ 42,774	$ —	$ —	$ 42,774
Segment Profit (Loss): Income (Loss) From Continuing Operations	$ 56,808	$ 45,230	$ (31,293)	$ 5,868	$112,450	$ 189,063	$ 193	$ (8,189)	$ 181,067
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 49,944	$199,327	$ 75,837	$ 164	$ 3,493	$ 328,765	$48,293(1)	$ 1,883	$ 378,941
	At September 30, 2003								
	(Thousands)								
Segment Assets	$1,384,058	$815,939	$1,002,718	$ 54,993	$125,684	$3,383,392	$78,441	$ 263,581(2)	$3,725,414

(1) Amount includes the acquisition of all of the partnership interests in Toro Partners, L.P. and is disclosed in Note K — Acquisitions.

(2) Amount includes $247,721 of assets of the former International segment, the majority of which has been discontinued with the sale of U.E. (see Note H — Discontinued Operations).

Geographic Information	For the Year Ended September 30 2005	2004	2003
		(Thousands)	
Revenues from External Customers(1):			
United States	$1,860,684	$1,867,335	$1,819,152
Canada	62,865	40,633	102,421
	$1,923,549	$1,907,968	$1,921,573

	At September 30		
	2005	2004	2003
		(Thousands)	
Long-Lived Assets:			
United States	$2,978,680	$2,941,779	$2,958,000
Canada	171,196	143,042	116,655
Assets of Discontinued Operations	—	228,179	219,695
	$3,149,876	$3,313,000	$3,294,350

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

Note J — Investments in Unconsolidated Subsidiaries

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

In September 2005, the Company recorded an impairment of $4.2 million of its equity investment in ESNE. Management believes that there is a decline in the market value of ESNE that is other than temporary in nature. This impairment was recorded in accordance with APB 18.

A summary of the Company's investments in unconsolidated subsidiaries at September 30, 2005 and 2004 is as follows:

	At September 30	
	2005	2004
	(Thousands)	
ESNE	$ 5,298	$10,045
Seneca Energy	5,839	5,169
Model City	1,521	1,230
	$12,658	$16,444

Note K — Acquisitions

On February 6, 2003, the Company acquired Empire from a subsidiary of Duke Energy Corporation for $189.2 million in cash (including cash acquired) plus $57.8 million of project debt. Empire's results of operations were incorporated into the Company's consolidated financial statements for the period subsequent to the completion of the acquisition on February 6, 2003. Empire is a 157-mile, 24-inch pipeline that begins at the United States/Canadian border at the Niagara River near Buffalo, New York, which is within the Company's service territory, and terminates in Central New York just north of Syracuse, New York. Empire delivers natural gas supplies to major industrial companies, utilities (including the Company's Utility segment), and power producers. Details of the acquisition are as follows (all figures in thousands):

Assets Acquired (Including $5.5 million of Goodwill)	$257,397
Liabilities Assumed	(68,192)
Cash Acquired at Acquisition	(8,053)
Cash Paid, Net of Cash Acquired	$181,152

On June 3, 2003, the Company acquired for approximately $47.8 million in cash (including cash acquired) all of the partnership interests in Toro, which owns and operates short-distance landfill gas pipeline companies that purchase, transport and resell landfill gas to customers in six states located primarily in the Midwestern United States. Toro's results of operations were incorporated into the Company's consolidated financial statements for the period subsequent to the completion of the acquisition on June 3, 2003. Details of the acquisition are as follows (all figures in thousands):

Assets Acquired	$48,319
Liabilities Assumed	(497)
Cash Acquired at Acquisition	(160)
Cash Paid, Net of Cash Acquired	$47,662

Note L — Intangible Assets

As a result of the Empire and Toro acquisitions discussed in Note K — 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, 2005			At September 30, 2004
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount
Intangible Assets Subject to Amortization:				
Long-Term Transportation Contracts	$ 8,580	$(2,851)	$ 5,729	$ 6,798
Long-Term Gas Purchase Contracts	31,864	(3,433)	28,431	30,025
Intangible Assets Not Subject to Amortization:				
Retirement Plan Intangible Asset (see Note F)	8,142	—	8,142	9,171
	$48,586	$(6,284)	$42,302	$45,994
Aggregate Amortization Expense				
For the Year Ended September 30, 2005	$ 2,663			
For the Year Ended September 30, 2004	$ 2,567			
For the Year Ended September 30, 2003	$ 1,054			

Amortization expense for the transportation contracts is estimated to be $1.1 million annually for 2006, 2007, and 2008. Amortization is estimated to be $0.5 million and $0.4 million for 2009 and 2010, respectively. Amortization expense for the gas purchase contracts is estimated to be $1.6 million annually for 2006, 2007, 2008, 2009, and 2010.

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. As a result of the decision to sell its majority interest in U.E., the Company determined it appropriate to present the Czech Republic operations as discontinued operations beginning in June 2005. Prior quarter amounts have been reclassified to reflect this change in presentation. 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 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)								
2005									
9/30/2005	$287,064	$ 34,926	$18,311(1)	$ 30,900(2)	$49,211(1)(2)	$0.22	$0.21	$0.58	$0.57
6/30/2005	$400,359	$ 63,028	$26,393	$ (7,237)(3)	$19,156(3)	$0.32	$0.31	$0.23	$0.23
3/31/2005	$735,842	$120,667	$63,981(4)	$ 6,702	$70,683(4)	$0.77	$0.75	$0.85	$0.83
12/31/2004	$500,284	$ 91,741	$44,830	$ 5,608	$50,438	$0.54	$0.53	$0.61	$0.60
2004									
9/30/2004	$267,495	$ 38,364	$13,832	$ (6,078)	$ 7,754	$0.17	$0.16	$0.09	$0.09
6/30/2004	$396,884	$ 73,682	$32,821(5)	$ (258)	$32,563(5)	$0.40	$0.39	$0.40	$0.39
3/31/2004	$753,225	$133,718	$68,078(6)	$ 8,977	$77,055(6)	$0.83	$0.82	$0.94	$0.93
12/31/2003	$490,364	$ 87,359	$39,534	$ 9,680(7)	$49,214(7)	$0.48	$0.48	$0.60	$0.60

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

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

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

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

(5) Includes expense of $0.8 million related to an adjustment to the gain on sale of timber properties recognized in 2003.

(6) Includes expense of $6.4 million due to the recognition of a pension settlement loss and income of $4.6 million due to an adjustment to the loss on sale of oil and gas properties recognized in September 2003.

(7) Includes income of $5.2 million related to tax rate changes in the Czech Republic.

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

At September 30, 2005, there were 18,369 holders 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 D — 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, 2005 and 2004, are shown below:

Quarter Ended	Price Range High	Price Range Low	Dividends Declared
2005			
9/30/2005	$36.00	$27.74	$.29
6/30/2005	$29.49	$26.20	$.29
3/31/2005	$29.75	$26.66	$.28
12/31/2004	$29.18	$27.01	$.28
2004			
9/30/2004	$28.43	$24.84	$.28
6/30/2004	$25.57	$23.75	$.28
3/31/2004	$26.48	$24.26	$.27
12/31/2003	$25.01	$21.71	$.27

Note O — Supplementary Information for Oil and Gas Producing Activities

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

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30 2005	At September 30 2004
	(Thousands)	
Proved Properties(1)	$1,650,788	$1,489,284
Unproved Properties	39,084	27,277
	1,689,872	1,516,561
Less — Accumulated Depreciation, Depletion and Amortization	721,397	609,469
	$ 968,475	$ 907,092

(1) Includes asset retirement costs of $30.8 million and $22.2 million at September 30, 2005 and 2004, respectively.

Costs related to unproved properties are excluded from amortization as they represent unevaluated properties that require additional drilling to determine the existence of oil and gas reserves. Following is a summary of such costs excluded from amortization at September 30, 2005:

	Total as of September 30, 2005	Year Costs Incurred 2005	2004	2003	Prior
		(Thousands)			
Acquisition Costs	$39,084	$18,691	$5,248	$6,871	$8,274

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

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ 287	$ (8)	$ (13)
Unproved	1,215	3,529	1,920
Exploration Costs	32,456	10,503	17,947
Development Costs	49,016	31,881	23,649
Asset Retirement Costs	8,051	2,292	242
	91,025	48,197	43,745
Canada			
Property Acquisition Costs:			
Proved	(1,551)	29	181
Unproved	4,668	3,167	6,217
Exploration Costs	22,943	22,624	6,641
Development Costs	12,198	5,500	17,745
Asset Retirement Costs	292	1,218	—
	38,550	32,538	30,784
Total			
Property Acquisition Costs:			
Proved	(1,264)	21	168
Unproved	5,883	6,696	8,137
Exploration Costs	55,399	33,127	24,588
Development Costs	61,214	37,381	41,394
Asset Retirement Costs	8,343	3,510	242
	$129,575	$80,735	$74,529

For the years ended September 30, 2005, 2004 and 2003, the Company spent $19.2 million, $12.1 million and $1.7 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2005	2004	2003
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $77, $72 and $69, respectively)	$151,004	$151,570	$148,104
Oil, Condensate and Other Liquids	160,145	139,301	118,277
Total Operating Revenues(1)	311,149	290,871	266,381
Production/Lifting Costs	38,442	39,677	39,162
Accretion Expense	2,220	1,756	1,800
Depreciation, Depletion and Amortization ($1.58, $1.41 and $1.29 per Mcfe of production)	67,097	73,396	70,127
Income Tax Expense	74,110	65,337	62,672
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	129,280	110,705	92,620

	Year Ended September 30		
	2005	2004	2003
	(Thousands, except per Mcfe amounts)		
Canada			
Operating Revenues:			
Natural Gas	49,275	30,359	26,992
Oil, Condensate and Other Liquids	12,875	10,018	62,908
Total Operating Revenues(1)	62,150	40,377	89,900
Production/Lifting Costs	12,683	8,176	33,038
Accretion Expense	228	177	802
Depreciation, Depletion and Amortization ($2.36, $1.83 and $1.30 per Mcfe of production)	23,108	14,922	26,165
Impairment of Oil and Gas Producing Properties(2)	—	—	42,774
Income Tax Expense (Benefit)	8,577	5,235	(3,273)
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	17,554	11,867	(9,606)
Total			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $77, $72 and $69, respectively)	200,279	181,929	175,096
Oil, Condensate and Other Liquids	173,020	149,319	181,185
Total Operating Revenues(1)	373,299	331,248	356,281
Production/Lifting Costs	51,125	47,853	72,200
Accretion Expense	2,448	1,933	2,602
Depreciation, Depletion and Amortization ($1.72, $1.47 and $1.30 per Mcfe of production)	90,205	88,318	96,292
Impairment of Oil and Gas Producing Properties(2)	—	—	42,774
Income Tax Expense	82,687	70,572	59,399
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$146,834	$122,572	$ 83,014

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

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

Reserve Quantity Information (unaudited)

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

	Gas MMcf					
	U. S.					
	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
Proved Developed and Undeveloped Reserves:						
September 30, 2002	57,864	73,316	78,274	209,454	48,767	258,221
Extensions and Discoveries	10,538	—	5,844	16,382	11,641	28,023
Revisions of Previous Estimates	(2,278)	1,213	2,224	1,159	(2,211)	(1,052)
Production	(18,441)	(4,467)	(5,123)	(28,031)	(5,774)	(33,805)
Sales of Minerals in Place	—	—	—	—	(270)	(270)
September 30, 2003	47,683	70,062	81,219	198,964	52,153	251,117
Extensions and Discoveries	2,632	—	3,784	6,416	15,925	22,341
Revisions of Previous Estimates	(4,984)	1,831	(1,111)	(4,264)	(11,004)	(15,268)
Production	(17,596)	(4,057)	(5,132)	(26,785)	(6,228)	(33,013)
Sales of Minerals in Place	(1)	(392)	—	(393)	—	(393)
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
Proved Developed Reserves:						
September 30, 2002	57,274	57,286	78,273	192,833	39,253	232,086
September 30, 2003	45,402	54,180	81,218	180,800	42,745	223,545
September 30, 2004	25,827	53,035	78,760	157,622	46,223	203,845
September 30, 2005	23,108	58,692	83,125	164,925	43,980	208,905

	Oil Mbbl					
	U.S.					
	Gulf Coast Region	West Coast Region	Appalachian Region	Total U.S.	Canada	Total Company
Proved Developed and Undeveloped Reserves:						
September 30, 2002	5,117	66,909	94	72,120	27,597	99,717
Extensions and Discoveries	104	—	46	150	729	879
Revisions of Previous Estimates	(365)	(185)	8	(542)	(4,119)	(4,661)
Production	(1,473)	(2,872)	(10)	(4,355)	(2,382)	(6,737)
Sales of Minerals in Place	—	—	—	—	(19,434)	(19,434)
September 30, 2003	3,383	63,852	138	67,373	2,391	69,764
Extensions and Discoveries	19	—	18	37	181	218
Revisions of Previous Estimates	213	(17)	11	207	(144)	63
Production	(1,534)	(2,650)	(20)	(4,204)	(324)	(4,528)
Sales of Minerals in Place	(1)	(303)	—	(304)	—	(304)
September 30, 2004	2,080	60,882	147	63,109	2,104	65,213
Extensions and Discoveries	99	—	63	162	204	366
Revisions of Previous Estimates	105	(1,253)	3	(1,145)	(186)	(1,331)
Production	(989)	(2,544)	(36)	(3,569)	(300)	(3,869)
Sales of Minerals in Place	—	—	—	—	(122)	(122)
September 30, 2005	1,295	57,085	177	58,557	1,700	60,257
Proved Developed Reserves:						
September 30, 2002	5,111	41,735	94	46,940	24,100	71,040
September 30, 2003	2,533	40,079	139	42,751	2,391	45,142
September 30, 2004	2,061	38,631	148	40,840	2,104	42,944
September 30, 2005	1,229	41,701	177	43,107	1,700	44,807

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

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

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		
	2005	2004	2003
		(Thousands)	
United States			
Future Cash Inflows	$6,138,522	$3,728,168	$2,684,286
Less:			
Future Production Costs	777,417	676,361	579,321
Future Development Costs	188,795	124,298	116,639
Future Income Tax Expense at Applicable Statutory Rate	1,868,548	995,327	613,893
Future Net Cash Flows	3,303,762	1,932,182	1,374,433
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,812,230	996,813	641,185
Standardized Measure of Discounted Future Net Cash Flows	1,491,532	935,369	733,248
Canada			
Future Cash Inflows	601,210	343,026	279,772
Less:			
Future Production Costs	136,338	111,519	85,817
Future Development Costs	12,197	13,222	9,787
Future Income Tax Expense at Applicable Statutory Rate	137,524	60,610	58,436
Future Net Cash Flows	315,151	157,675	125,732
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	108,508	46,945	40,575
Standardized Measure of Discounted Future Net Cash Flows	206,643	110,730	85,157
Total			
Future Cash Inflows	6,739,732	4,071,194	2,964,058
Less:			
Future Production Costs	913,755	787,880	665,138
Future Development Costs	200,992	137,520	126,426
Future Income Tax Expense at Applicable Statutory Rate	2,006,072	1,055,937	672,329
Future Net Cash Flows	3,618,913	2,089,857	1,500,165

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,920,738	1,043,758	681,760
Standardized Measure of Discounted Future Net Cash Flows	$1,698,175	$1,046,099	$ 818,405

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

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
United States			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	$ 935,369	$ 733,248	$ 781,087
Sales, Net of Production Costs	(272,707)	(251,194)	(227,219)
Net Changes in Prices, Net of Production Costs	1,093,353	592,326	11,130
Purchases of Minerals in Place	—	—	—
Sales of Minerals in Place	(762)	(5,554)	—
Extensions and Discoveries	100,102	16,638	29,266
Changes in Estimated Future Development Costs	(89,805)	(40,042)	(35,062)
Previously Estimated Development Costs Incurred	25,038	32,653	36,423
Net Change in Income Taxes at Applicable Statutory Rate	(362,956)	(166,055)	24,796
Revisions of Previous Quantity Estimates	25,055	(5,107)	(3,572)
Accretion of Discount and Other	38,845	28,456	116,399
Standardized Measure of Discounted Future Net Cash Flows at End of Year	1,491,532	935,369	733,248

	Year Ended September 30		
	2005	2004	2003
		(Thousands)	
Canada			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	110,730	85,157	245,095
Sales, Net of Production Costs	(49,467)	(32,201)	(56,862)
Net Changes in Prices, Net of Production Costs	174,985	29,230	8,167
Purchases of Minerals in Place	—	—	—
Sales of Minerals in Place	(3,751)	—	(120,960)
Extensions and Discoveries	31,028	36,986	28,241
Changes in Estimated Future Development Costs	(11,007)	(8,491)	(14,045)
Previously Estimated Development Costs Incurred	12,032	5,055	29,657
Net Change in Income Taxes at Applicable Statutory Rate	(51,541)	(2,640)	(6,280)
Revisions of Previous Quantity Estimates	(5,990)	(19,369)	(41,205)
Accretion of Discount and Other	(376)	17,003	13,349
Standardized Measure of Discounted Future Net Cash Flows at End of Year	206,643	110,730	85,157
Total			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	1,046,099	818,405	1,026,182
Sales, Net of Production Costs	(322,174)	(283,395)	(284,081)
Net Changes in Prices, Net of Production Costs	1,268,338	621,556	19,297
Purchases of Minerals in Place	—	—	—
Sales of Minerals in Place	(4,513)	(5,554)	(120,960)
Extensions and Discoveries	131,130	53,624	57,507
Changes in Estimated Future Development Costs	(100,812)	(48,533)	(49,107)
Previously Estimated Development Costs Incurred	37,070	37,708	66,080
Net Change in Income Taxes at Applicable Statutory Rate	(414,497)	(168,695)	18,516
Revisions of Previous Quantity Estimates	19,065	(24,476)	(44,777)
Accretion of Discount and Other	38,469	45,459	129,748
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$1,698,175	$1,046,099	$ 818,405

Note P — Subsequent Event

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. It is expected that this share repurchase program will be funded with cash provided by operating activities and/or through the use of the Company's bi-lateral lines of credit. The timing of repurchases will depend on market conditions.

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts(1)	Deductions(2)	Balance at End of Period
			(Thousands)		
Year Ended September 30, 2005					
Reserve for Doubtful Accounts	$17,440	$31,113	$2,480	$24,093	$26,940
Deferred Tax Valuation Allowance	$ 2,877	$ —	$ —	$ —	$ 2,877
Year Ended September 30, 2004					
Reserve for Doubtful Accounts	$17,943	$20,328	$ —	$20,831	$17,440
Deferred Tax Valuation Allowance	$ 6,357	$ (3,480)	$ —	$ —	$ 2,877
Year Ended September 30, 2003					
Reserve for Doubtful Accounts	$17,299	$17,275	$ —	$16,631	$17,943
Deferred Tax Valuation Allowance	$ —	$ 6,357	$ —	$ —	$ 6,357

(1) 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).

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

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

None

Item 9A *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

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

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 generally accepted accounting principles in the United States of America (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, 2005. 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, 2005.

Management's assessment of the effectiveness of the Company's internal control over financial reporting as of September 30, 2005 has been audited by PricewaterhouseCoopers LLP, the independent registered public accounting firm that also audited the Company's consolidated financial statements, and their 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, 2005 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B *Other Information*

None

PART III

Item 10 *Directors and Executive Officers of the Registrant*

The information required by this item concerning the directors of the Company is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 16, 2006 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2005. 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 2009," "Directors Whose Terms Expire in 2008," "Directors Whose Terms Expire in 2007," and "Compliance with Section 16(a) of the Securities Exchange Act of 1934" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

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

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

Item 11 *Executive Compensation*

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 16, 2006 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2005. The information concerning executive compensation is set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee" and the "Corporate Performance Graph," is incorporated herein by reference.

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

Equity Compensation Plan Information

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 16, 2006 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2005. The equity compensation plan information is set forth in the definitive Proxy Statement under the heading "Equity Compensation Plan Information" and is incorporated herein by reference.

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 16, 2006 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2005. The information concerning security ownership of certain beneficial owners is set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(b) Security Ownership of Management

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 16, 2006 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2005. 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*

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 16, 2006 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2005. The information regarding certain relationships and related transactions is set forth in the definitive Proxy Statement under the heading "Compensation Committee Interlocks and Insider Participation" and is incorporated herein by reference.

Item 14 *Principal Accountant Fees and Services*

The information required by this item is omitted pursuant to Instruction G of Form 10-K since the Company's definitive Proxy Statement for its February 16, 2006 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2005. 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 on December 9, 2004 (Exhibit 3(ii), Form 8-K dated December 9, 2004 in File No. 1-3880)
(4)	Instruments Defining the Rights of Security Holders, Including Indentures:
•	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
•	Third Supplemental Indenture, dated as of December 1, 1982,to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
•	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992 in File No. 1-3880)
•	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992 in File No. 1-3880)
•	Thirteenth Supplemental Indenture, dated as of March 1,1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
•	Fourteenth Supplemental Indenture, dated as of July 1, 1993,to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993 in File No. 1-3880)
•	Fifteenth Supplemental Indenture, dated as of September 1,1996, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
•	Indenture dated as of October 1, 1999, between the Company and The Bank of New York (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Officers Certificate Establishing Medium-Term Notes, dated October 14, 1999 (Exhibit 4.2, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amended and Restated Rights Agreement, dated as of April 30,1999, between the Company and HSBC Bank USA (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880)
•	Certificate of Adjustment, dated September 7, 2001, to the Amended and Restated Rights Agreement dated as of April 30,1999, between the Company and HSBC Bank USA (Exhibit 4, Form 8-K dated September 7, 2001 in File No. 1-3880)
•	Officers Certificate establishing 6.50% Notes due 2022, dated September 18, 2002 (Exhibit 4, Form 8-K dated October 3, 2002 in File No. 1-3880)

Exhibit Number	Description of Exhibits
•	Officers Certificate establishing 5.25% Notes due 2013, dated February 18, 2003 (Exhibit 4, Form 10-Q for the quarterly period ended March 31, 2003 in File No. 1-3880)
(10)	Material Contracts:
(ii)	Contracts upon which the Company's business is substantially dependent:
10.1	Credit Agreement, dated as of August 19, 2005, among the Company, the Lenders Party Thereto and JPMorgan Chase Bank, N.A., as Administrative Agent
(iii)	Compensatory plans for officers:
•	Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, among the Company, National Fuel Gas Distribution Corporation and each of Philip C. Ackerman, Anna Marie Cellino, Paula M, Ciprich, Donna L. DeCarolis, James D. Ramsdell, Dennis J. Seeley, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880)
•	Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, among the Company, National Fuel Gas Supply Corporation and John R. Pustulka (Exhibit 10.2, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880)
•	Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, among the Company, Seneca Resources Corporation and James A. Beck (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880)
•	National Fuel Gas Company 1993 Award and Option Plan, dated February 18, 1993 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880)
•	Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated October 27, 1995 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
•	Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 11, 1996 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
•	Amendment to National Fuel Gas Company 1993 Award and Option Plan, dated December 18, 1996 (Exhibit 10, Form 10-Q for the quarterly period ended December 31, 1996 in File No. 1-3880)
•	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)
10.2	National Fuel Gas Company 1993 Award and Option Plan, amended through September 8, 2005
•	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)
10.3	National Fuel Gas Company 1997 Award and Option Plan, amended through September 8, 2005
•	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)
10.4	Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005
•	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)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated, effective March 9, 2005 (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2005 in File No. 1-3880)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, 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)

Exhibit Number	Description of Exhibits
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998 in File No. 1-3880)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999 in File No. 1-3880)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001 in File No. 1-3880)
10.5	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005
10.6	Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005
•	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)
10.7	Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 20055
•	Amended Restated Split Dollar Insurance Agreement, effective June 15, 2000, among the Company, Bernard J. Kennedy, and Joseph B. Kennedy, as Trustee of the Trust under the Agreement dated January 9, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2000 in File No. 1-3880)
•	Contingent Benefit Agreement effective June 15, 2000, between the Company and Bernard J. Kennedy (Exhibit 10.2, Form 10-Q for the quarterly period ended June 30, 2000 in File No. 1-3880
•	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and Dennis J. Seeley (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Dennis J. Seeley, dated March 29, 1999 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Split Dollar Insurance and Death Benefit Agreement dated September 15, 1997, between the Company and Bruce H. Hale (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and Bruce H. Hale, dated March 29, 1999 (Exhibit 10.12, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)

Exhibit Number	Description of Exhibits
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001, in File No. 1-3880)
•	National Fuel Gas Company and Participating Subsidiaries 1996 Executive Retirement Plan Trust Agreement (II), dated May 10, 1996 (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
•	National Fuel Gas Company Participating Subsidiaries Executive Retirement Plan 2003 Trust Agreement (I), dated September 1, 2003 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
•	National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 8-K dated June 3, 2005 in File No. 1-3880)
•	Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of March 20, 1997 regarding the Retainer Policy for Non-Employee Directors (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1997 in File No. 1-3880)
•	Retirement Benefit Agreement for David F. Smith, dated September 22, 2003,between the Company and David F. Smith (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2003 in File No. 1-3880)
10.8	Amendment No. 1 to the Retirement Benefit Agreement for David F. Smith, dated September 8, 2005, between the Company 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)
•	Retirement and Consulting Agreement, dated September 5, 2001, between the Company and Bernard J. Kennedy (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2004 in File No. 1-3880)
•	Retirement Supplement Agreement, dated January 11, 2002, between the Company and Joseph P. Pawlowski (Exhibit 10.6, Form 10-K/A for fiscal year ended September 30, 2001 in File No. 1-3880)
•	Amendment No. 1 to Retirement Supplement Agreement, dated March 11, 2004, between the Company and Joseph P. Pawlowski (Exhibit 10(iii), Form 10-Q for the quarterly period ended March 31, 2004 in File No. 1-3880)
10.9	Retirement Agreement, dated August 1, 2005, between the Company and Bruce H. Hale
10.10	Commission Agreement, dated August 1, 2005, between the Company and Bruce H. Hale
(12)	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2001 through 2005
(21)	Subsidiaries of the Registrant: See Item 1 of Part I of this Annual Report on Form 10-K

Exhibit Number	Description of Exhibits
(23)	Consents of Experts:
23.1	Consent of Ralph E. Davis Associates, Inc. regarding Seneca Resources Corporation
23.2	Consent of Ralph E. Davis Associates, Inc. regarding Seneca Energy Canada, Inc.
23.3	Consent of Independent Registered Public Accounting Firm
(31)	Rule 13a-15(e)/15d-15(e) Certifications
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-15(e)/15d-15(e) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-15(e)/15d-15(e) of the Exchange Act.
(32)	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
(99)	Additional Exhibits:
99.1	Report of Ralph E. Davis Associates, Inc. regarding Seneca Resources Corporation
99.2	Report of Ralph E. Davis Associates, Inc. regarding Seneca Energy Canada, Inc.
99.3	Company Maps

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

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

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

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

- Incorporated herein by reference as indicated. All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K.

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, President and Chief Executive Officer

Date: December 8, 2005

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	Date
/s/ P. C. ACKERMAN P. C. Ackerman	Chairman of the Board, President, Chief Executive Officer and Director	December 8, 2005
/s/ R. T. BRADY R. T. Brady	Director	December 8, 2005
/s/ R. D. CASH R. D. Cash	Director	December 8, 2005
/s/ R. E. KIDDER R. E. Kidder	Director	December 8, 2005
/s/ C. G. MATTHEWS C. G. Matthews	Director	December 8 2005
/s/ G. L. MAZANEC G. L. Mazanec	Director	December 8, 2005
/s/ R. G. REITEN R. G. Reiten	Director	December 8, 2005
/s/ J. F. RIORDAN J. F. Riordan	Director	December 8, 2005
/s/ R. J. TANSKI R. J. Tanski	Treasurer and Principal Financial Officer	December 8, 2005
/s/ K. M. CAMIOLO K. M. Camiolo	Controller and Principal Accounting Officer	December 8, 2005

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Principal Officers

National Fuel Gas Company

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

Dennis J. Seeley
Vice President

David F. Smith
Vice President

Ronald J. Tanski
Treasurer and Principal Financial Officer

Karen M. Camiolo
Controller and Principal Accounting Officer

Anna Marie Cellino
Secretary

Paula M. Ciprich
General Counsel

Principal Officers of Principal Subsidiaries

National Fuel Gas Distribution Corporation

Philip C. Ackerman
Chairman of the Board

Dennis J. Seeley
President

Anna Marie Cellino
Senior Vice President and Secretary

Ronald J. Tanski
Senior Vice President and Treasurer

James D. Ramsdell
Senior Vice President

Carl M. Carlotti
Vice President

Bruce D. Heine
Vice President

Jay W. Lesch
Vice President

Steven Wagner
Vice President

Karen M. Camiolo
Controller

National Fuel Gas Supply Corporation

Philip C. Ackerman
Chairman of the Board

David F. Smith
President

John R. Pustulka
Senior Vice President

Ronald J. Tanski
Treasurer and Secretary

Karen M. Camiolo
Controller

Seneca Resources Corporation

Philip C. Ackerman
Chairman of the Board

James A. Beck
President

Barry L. McMahan
Senior Vice President

Thomas L. Atkins
Treasurer

Donald P. Butler
Secretary

National Fuel Resources, Inc.

Donna L. DeCarolis
President

Highland Forest Resources, Inc.

Philip C. Ackerman
Chairman of the Board

James A. Beck
President

Thomas L. Atkins
Treasurer

Donald P. Butler
Secretary

Directors

Philip C. Ackerman [6,10]
Chairman of the Board of Directors of the Company since January 2002. Chief Executive Officer since October 2001, and President since July 1999. Chairman and President of certain subsidiaries of the Company. Board member since 1994.

Robert T. Brady [3,5,8]
Chairman, President and Chief Executive Officer of Moog Inc. Director of Astronics Corporation, M&T Bank Corporation and Seneca Foods Corporation. Chairman of the Buffalo Niagara Partnership. Board member since 1995.

R. Don Cash [1,3,7]
Chairman Emeritus and Director of Questar Corporation. Former Chairman, Chief Executive Officer and President of Questar Corporation. Director of Zions Bancorporation, Associated Electric and Gas Insurance Services Limited, and TODCO (The Offshore Drilling Company). Board member since 2003.

Rolland E. Kidder [1]
Executive Director of the Robert H. Jackson Center, Inc. in Jamestown, N.Y. Former Chairman and President of Kidder Exploration, Inc. Former Trustee of the New York Power Authority. Board member since 2002.

Craig G. Matthews [2,9]
Former President and Chief Executive Officer of NUI Corporation Former Vice Chairman and Chief Operating Officer of KeySpan Corporation. Director of Amerada Hess Corporation. Board member since February 2005.

George L. Mazanec [1,4,5,9]
Former Vice Chairman of PanEnergy Corporation (now part of Duke Energy Corporation). Director of Dynegy Inc. Director of the Northern Trust Bank of Texas, NA, and Associated Electric and Gas Insurance Services Limited. Former Chairman of the Management Committee of Maritimes & Northeast Pipeline, L.L.C. Board member since 1996.

Richard G. Reiten [1,7]
Director and former Chairman and Chief Executive Officer of Northwest Natural Gas Company. Director of Associated Electric and Gas Insurance Services Limited, BlueCross BlueShield of Oregon, and The Regence Group. Board member since 2004.

John F. Riordan [5,7]
President and Chief Executive Officer of the Gas Technology Institute. Director of Nicor, Inc. Former President and Chief Executive Officer of MIDCON Corporation. Board member since 2000.

[1] Member of Audit Committee
[2] Chairman, Audit Committee
[3] Member of Compensation Committee
[4] Chairman, Compensation Committee
[5] Member of Executive Committee
[6] Chairman, Executive Committee
[7] Member of Nominating/Corporate Governance Committee
[8] Chairman, Nominating/Corporate Governance Committee
[9] Member of Finance Committee
[10] Chairman, Finance Committee

Investor Information

Common Stock Transfer Agent and Registrar

The Bank of New York
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 10, 2005, 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, 2005.

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, the agent for the Plan, at:

The Bank of New York*
Shareholder Relations
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 address shown.

Trustee for Debentures

The Bank of New York
101 Barclay Street
New York, NY 10286

Annual Meeting

The Annual Meeting of Shareholders will be held at 10 a.m. (local time) on Thursday, February 16, 2006, at The Ritz-Carlton Hotel, 2600 Tiburon Drive, Naples, FL 34109. Formal notice of the meeting, proxy statement and proxy will be mailed to shareholders of record as of the close of business on December 19, 2005.

Investor Relations

Investors or financial analysts desiring information should contact:

Ronald J. Tanski, Treasurer
Tel. (716) 857-6981

Margaret M. Suto, Director, Investor Relations
Tel. (716) 857-6987
E-mail: sutom@natfuel.com

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Additional Shareholder Reports

Additional copies of this report and the Financial and Statistical Supplement to the 2005 Annual Report can be obtained without charge by writing to or calling:

Anna Marie Cellino, Corporate Secretary
Tel. (716) 857-7858

Margaret M. Suto, Director, Investor Relations
Tel. (716) 857-6987

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Independent Accountants

PricewaterhouseCoopers LLP
3600 HSBC Center
Buffalo, NY 14203

 For up-to-date information, we have two sources for your use. You may call 1-800-334-2188 at any time to receive National Fuel's current stock price and trade volume or to hear the latest news releases. You may also have news releases faxed or mailed to you. National Fuel's website can be found at **http://www.nationalfuelgas.com.** You may sign up there to receive news releases automatically by e-mail. Simply go to the News section and subscribe.

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