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FORM FOR SUBMISSION OF PAPER FORMAT EXHIBITS
BY ELECTRONIC FILERS

National Fuel Gas Company
Exact Name of Registrant as Specified in Charter

0000070145
Registrant CIK Number

Form U5S for the Fiscal Year Ended September 30, 2001
Electronic Report, Schedule or Registration Statement
of Which the Documents Are a Part (give period of report)

~~[illegible]~~ 30-9
SEC File Number of Registration Statement
or Schedule of Which Documents Are a Part
or Commission File Number if a Form 10-K,
10-Q or 8-K

Name of Person Filing the Document
(If Other than the Registrant)

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THOMSON
FINANCIAL

SIGNATURES

Filings Made by the Registrant:

The Registrant has duly caused this form to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Buffalo, State of New York January 28, 2002.

National Fuel Gas Company
(Registrant)

By: [signature]
(Name and Title)

Joseph P. Pawlowski
Treasurer and Principal Accounting Officer

Filings Made by Person Other Than the Registrant:

After reasonable inquiry and to the best of my knowledge and belief, I certify on ____________, 19__, that the information set forth in this statement is true and complete.

By:______________________________
(Name)

____
(Title)

NATIONAL FUEL GAS COMPANY
FORM U5S FOR THE FISCAL YEAR ENDED SEPTEMBER 30, 2001
INDEX FOR EXHIBITS FILED UNDER FORM SE

Exhibit A.(2) National Fuel Gas Company 2001 Annual Report to Shareholders.

National Fuel Gas Company

2001 ANNUAL REPORT AND FORM 10-K

strong links

Strategic Location

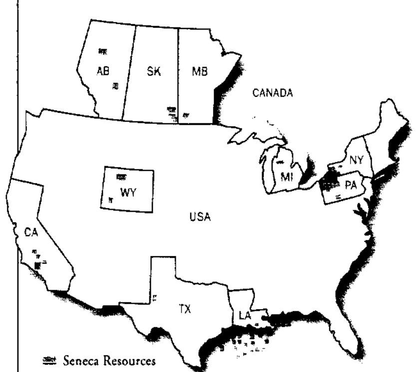
Outstanding Workforce

National Fuel Gas Company, incorporated in 1902, is a diversified energy company with its headquarters in Buffalo, New York. The Company's $3.4 billion in assets is distributed among six principal business segments: Exploration and Production, Pipeline and Storage, Utility, Energy Marketing, Timber and International.

National Fuel's history dates to the earliest period 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.

At a Glance

Exploration and Production



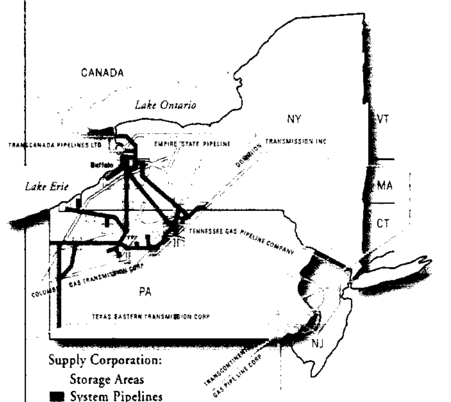
IN 2001:

- Net income of $71.8 million or $0.89 per diluted share, excluding the 4th quarter non-cash write down of the Canadian oil and gas assets. Including the write down, net loss of $32.3 million or ($0.40) per diluted share.
- Record production of 88.1 Bcfe was a 21% increase over last year's production of 72.6 Bcfe.
- Acquisition of second Canadian company, Player Petroleum Corporation, helped mitigate gas production decline in the Gulf Coast region.

OUTLOOK:*

- Production goal of 100 Bcfe would extend production growth to seventh consecutive year. Includes plans to drill over 200 wells.
- On-shore production emphasized for 2002.
- Capital budget of $141 million planned, excluding acquisitions.

Pipeline and Storage



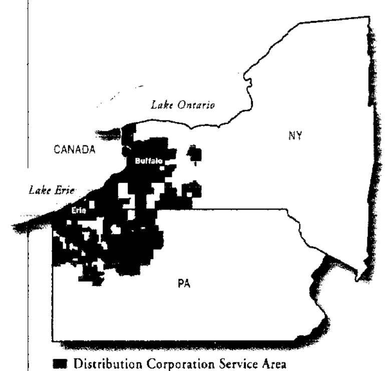
IN 2001:

- Net income of $40.4 million or $0.50 per diluted share.
- Developing plans to construct Northwinds Pipeline project, a 215-mile pipeline with service from Canada at Kirkwall, Ontario to Leidy, Pennsylvania.
- Negotiated Ellisburg station expansion project to add nearly 40% additional compression in early fiscal 2003.

OUTLOOK:*

- Use engineering efficiencies to increase storage field deliverability and capacity.
- Pursue additional projects to support gas-fired electric generation facilities through system interconnections.
- Focus expansion plans to increase transportation capacity into Leidy Hub.

Utility



IN 2001:

- Net income of $60.7 million or $0.76 per diluted share.
- Continued to work with select customers to integrate distributed electric generation technologies at their facilities.
- Handled record number of customer contacts while maintaining superior service levels.

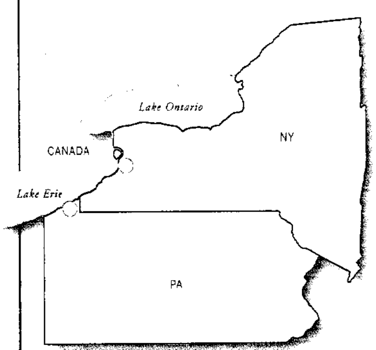
OUTLOOK:*

- Continue to pursue opportunities to remove certain electric tariff restrictions to allow for expanded use of distributed electric generation technologies in western New York.
- Focus on sustaining excellence in customer service while incorporating cost control measures and additional operating efficiencies.
- Explore opportunities to more effectively use assets and enhance their value.

CONTENTS

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

Energy Marketing



National Fuel Resources

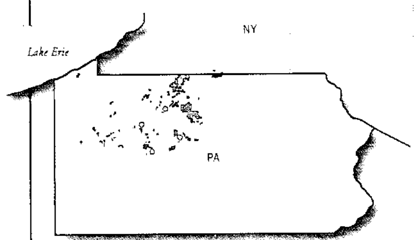
IN 2001:

- **Net loss of $3.4 million or ($0.04) per diluted share due to increased bad debt and interest expenses.**
- **New management team in place to redirect operations.**

OUTLOOK:*

- **Refocus on traditional strength of providing quality service to local markets.**
- **Continue to improve margins, increase market share and product offerings, and pursue revenue expansion opportunities.**

Timber



Seneca Acreage
Sawmills

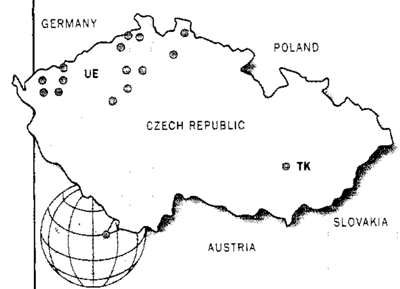
IN 2001:

- **Net income of $7.7 million or $0.10 per diluted share.**
- **Increased production by 14% to 28.0 million board feet.**

OUTLOOK:*

- **Continue to focus on profitability of hardwoods, especially cherry veneer.**

International



Horizon Energy

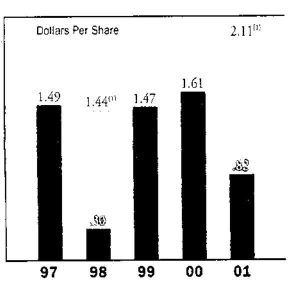
IN 2001:

- **Net loss of $3.0 million or ($0.04) per diluted share resulted primarily from lower heat and electric margins due to warmer weather.**
- **Environmental compliance program for 10 coal-fired boilers nearly complete.**

OUTLOOK:*

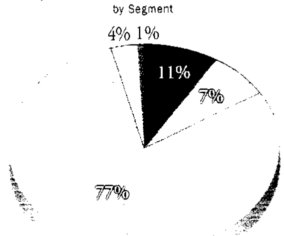
- **Focus on efficient operations and higher value markets.**
- **Project development group pursuing new opportunities including projects in Italy and Bulgaria.**

Diluted Earnings Per Share



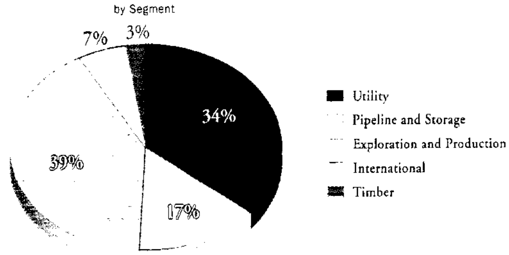
(1) Excludes special items for impairment of oil and gas producing assets in 1998 and 2001 and for cumulative effect of change in accounting in 1998.

Expenditures for Long-Lived Assets
by Segment



Total: $385.1 million

Net Plant
by Segment



Total: $2.8 billion

Highlights

Year Ended September 30	2001	2000	1999	1998	1997
Operating Revenues *(Thousands)*	**$2,100,352**	$1,425,277	$1,263,274	$1,248,000	$1,265,812
Net Income Available for Common Stock *(Thousands)*	**$ 65,499**	$ 127,207	$ 115,037	$ 23,188	$ 114,688
Net Income Available for Common Stock Before Special Items *(Thousands)*	**$ 169,539**(1)	$ 127,207	$ 115,037	$ 111,418(3)	$ 114,688
Return on Average Common Equity	**6.4%**	13.0%	12.6%	2.6%	13.0%
Return on Average Common Equity Before Special Items	**15.8%**(1)	13.0%	12.6%	11.9%(3)	13.0%
Per Common Share(4)					
Basic Earnings	**$ 0.83**	$ 1.63	$ 1.49	$ 0.30	$ 1.51
Diluted Earnings	**$ 0.82**	$ 1.61	$ 1.47	$ 0.30	$ 1.49
Basic Earnings Before Special Items	**$ 2.14**(1)	$ 1.63	$ 1.49	$ 1.45(3)	$ 1.51
Diluted Earnings Before Special Items	**$ 2.11**(1)	$ 1.61	$ 1.47	$ 1.44(3)	$ 1.49
Dividends Paid	**$ 0.97**	$ 0.94	$ 0.91	$ 0.88	$ 0.85
Dividend Rate at Year-End	**$ 1.01**	$ 0.96	$ 0.93	$ 0.90	$ 0.87
Book Value at Year-End	**$12.63**	$12.55	$12.09	$11.57	$11.97
Common Shares Outstanding at Year-End(4)	**79,406,105**	78,659,606	77,674,998	76,937,590	76,331,776
Weighted Average Common Shares Outstanding(4)					
Basic	**79,053,444**	78,233,842	77,327,962	76,632,794	76,167,028
Diluted	**80,361,258**	79,166,200	78,083,456	77,407,052	76,880,036
Average Common Shares Traded Daily(4)	**192,937**	161,271	121,327	125,482	118,912
Common Stock Price(4)					
High	**$32.25**	$29.41	$25.00	$24.56	$22.72
Low	**$21.96**	$19.69	$18.75	$19.81	$18.31
Close	**$23.03**	$28.03	$23.59	$23.50	$22.00
Net Cash Provided by Operating Activities *(Thousands)*	**$ 414,144**	$ 238,246	$ 267,504	$ 249,863	$ 294,662
Total Assets *(Thousands)*	**$3,445,566**	$3,251,031	$2,842,586	$2,684,459	$2,267,331
Expenditures for Long-Lived Assets *(Thousands)*	**$ 385,103**	$ 398,777	$ 265,527	$ 507,537	$ 248,311
Volume Information					
Utility Throughput-MMcf					
Gas Sales	**104,186**	97,617	101,675	108,599	127,501
Gas Transportation	**66,283**	71,862	64,086	60,080	57,310
Pipeline & Storage Throughput-MMcf					
Gas Transportation	**321,555**	313,548	308,303	313,048	300,302
Production Volumes					
Gas-MMcf	**41,004**	41,670	37,166	36,474	38,586
Oil-Mbbl	**7,857**	5,147	4,016	2,614	1,902
Total-MMcfe	**88,146**	72,552	61,262	52,161	49,998
Proved Reserves					
Gas-MMcf	**322,380**	301,667	320,792	325,065	232,449
Oil-Mbbl	**115,328**	119,697	75,819	66,591	17,981
Total-MMcfe	**1,014,348**	1,019,849	775,706	724,611	340,335
Energy Marketing Volumes-MMcf					
Gas	**37,427**	35,465	34,454	26,453	21,024
International Sales Volumes					
Heating (Gigajoules)	**9,978,118**	10,222,024	10,047,042	7,116,776	262,615
Electricity (Megawatt hours)	**1,019,901**	1,147,303	1,138,980	763,848	—
Average Number of Utility Retail Customers	**678,357**	656,792	691,080	702,283	729,233
Average Number of Utility Transportation Customers	**54,140**	78,610	41,515	28,224	2,013
Number of Employees at September 30	**3,235**(2)	3,597(2)	3,807(2)	3,944(2)	2,524

(1) Excludes oil and gas asset impairment of ($104.0) million or ($1.32) per common share (basic) and ($1.29) per common share (diluted).
(2) Includes 991, 1,201, 1,406 and 1,390 international employees at September 30, 2001, 2000, 1999 and 1998, respectively.
(3) Excludes oil and gas asset impairment of ($79.1) million or ($1.03) per common share (basic) and ($1.02) per common share (diluted) and Cumulative Effect of Change in Accounting of ($9.1) million or ($0.12) per common share (basic and diluted).
(4) All Common Share data reflects two-for-one stock split on September 7, 2001.

To Our Shareholders

Philip C. Ackerman (left), President and Chief Executive Officer, and Bernard J. Kennedy, Chairman of the Board

Diversity of assets has long been a defining characteristic of National Fuel's successful growth strategy, but it has never been more important than it is today. In this world of sudden and unexpected change, we cannot afford to channel our resources into a single enterprise. Instead, we have forged a chain of investments, each link independent enough to stand on its own while enhancing the strength of the others.*

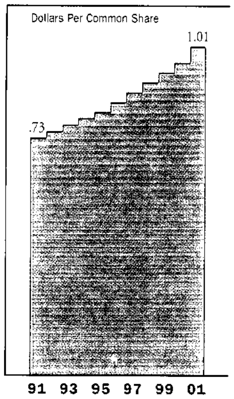
The Company's earnings of $65.5 million or $0.82 per share[1] do not truly reflect our otherwise exceptional performance this year. For our first three quarters we were on track to deliver record earnings, fueled by high commodity prices and solid performances by our Utility and Pipeline and Storage segments. But natural gas prices declined precipitously over the summer months and by September 30th, we could not avoid a "ceiling test" write down required under the full-cost method of accounting for oil and gas operations. As a result of low natural gas prices, we recorded a non-cash impairment relating to our Canadian properties of $104.0 million after tax, or ($1.29) per share. Absent the impairment, earnings per share for fiscal 2001 were $2.11, a 31% increase over last year's record earnings of $1.61 per share.

(1) All references to earnings per share are to diluted earnings per share. All references to per share figures reflect the stock split.

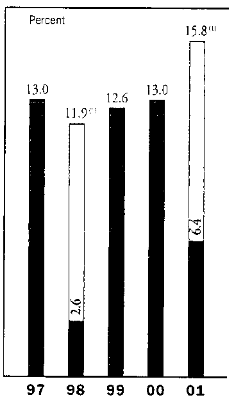
In 2001, your Board of Directors took three actions of particular positive significance to shareholders. The dividend increase to $1.01 per share annually was the 31st consecutive increase and the 99th year of uninterrupted dividends. The two-for-one stock split was our third in the last 20 years. Finally, the conversion of Stock Appreciation Rights (SARs) to options, recommended by the Directors and approved by the shareholders, essentially eliminated the variable charges that mark-to-market accounting required for SARs and the impact it would have continued to have on earnings.

Through the trials of more than two centuries, Americans have proved themselves capable of withstanding great adversity. The September 11th terrorist attacks on America have compelled virtually every sector of our society to reevaluate long-held standards and practices. While our associates in the industry are our competitors in the marketplace, we are nonetheless unified in our concern for our fellow citizens and the security of our nation's energy supply. With the balanced portfolio we have built over the years, the diverse geography

Annual Dividend Rate at Year End



Return on Average Common Equity



(1) Excludes special items for impairment of oil and gas producing assets in 1998 and 2001 and for cumulative effect of change in accounting in 1998.

of our assets, our standard contingency planning and the preparations we made for "Y2K", no single attack, however unthinkable, could wipe out the value of your Company.* However, no matter what preparations we might make, it is beyond our individual power to prevent another attack by fanatics.* But what we can do, and have done, is back up key facilities and thoroughly prepare for recovery in order to minimize any disruptions of service.

Because our society is heavily dependent on electricity, we see great potential in the further development and marketing of equipment for distributed generation, which would offer both commercial and residential customers an alternative source of electricity as backup against an interruption of the grid's supply.* In recent years, brownouts or blackouts have crippled industry in some parts of the country when electric supply fell short of demand during periods of peak use. We also must consider the devastating effects of the disruption of electrical service in the event of attacks on large generating plants. While the necessary equipment is currently costly, many users are deciding that the business interruptions occasioned by loss of power are even more costly. As equipment prices decline, we foresee an opportunity for National Fuel to create a new, non-regulated segment that would own, operate and maintain the units needed for distributed generation.*

We begin our new fiscal year with warmer-than-normal temperatures throughout the eastern United States, gas prices less than one-half of those a year ago and oil prices down 25%. Consequently, even though it is unlikely that our earnings next year will match this year's robust level excluding the impact of the "ceiling test" write down, we do anticipate an opportunity to increase our reserves and production, and expand our Pipeline and Storage facilities as America assesses her energy vulnerability.*

Following is a report of our accomplishments over the past year and some of our plans for the year to come.

Exploration and Production

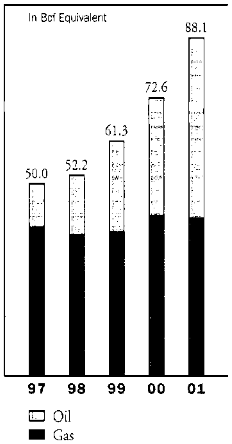
Record production of 88.1 billion cubic feet equivalent (Bcfe) was a 21% increase over last year's production of 72.6 Bcfe. Total fiscal 2001 revenues for this segment were $398.3 million — a 67% increase over total revenues of $238.1 million for fiscal 2000. Excluding the impairment, this segment provided earnings of $71.8 million or $0.89 per share, an increase of more than 100% over last year's earnings of $34.9 million or $0.44 per share. As it was, the vagaries of commodity pricing and the "ceiling test" of the full-cost method accounting rules required a ($1.29) per share write down of our Canadian oil and gas assets, resulting in a net loss of $32.3 million or ($0.40) per share this year. This write down is not the equivalent of a loss of reserves; the reserves still exist and as gas prices recover, they will contribute to earnings.*

We are continuing our long-term strategy of shifting our emphasis away from offshore production in the Gulf of Mexico.* In fiscal 2001, we sold one offshore block, swapped interests in two others, and started marketing a sixteen-block farm-out package, for which the initial response has been very encouraging.*

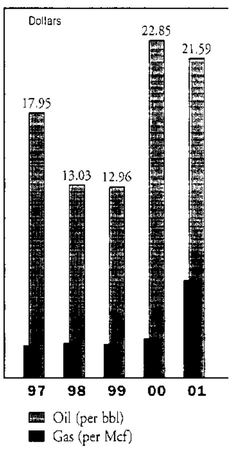
In May 2001, the Exploration and Production segment initiated a 50-well drilling program on its Appalachian properties near St. Marys, Pa. The majority of these wells are connected to a new gathering system, which feeds into our existing pipelines.

In June 2001, the Exploration and Production segment acquired Player Petroleum Corporation, adding to its asset base 60.2 Bcf equivalent of proven reserves (93% natural gas) net of royalties, interests in six major processing facilities and 97,000 net acres of leased acreage. A large portion of the new property is adjacent to the Red Deer River near Drumheller, Alberta, where natural gas wells, like the one in the foreground, speckle the unique landscape.

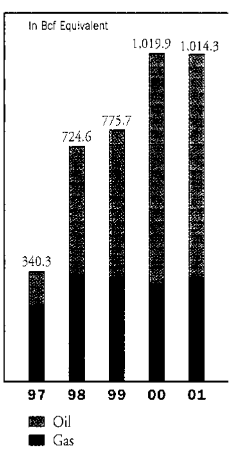
Oil and Gas Production



Oil and Gas Prices
Weighted Average After Hedging



Proved Developed and Undeveloped Reserves



We continue to evaluate promising core properties in Canada as well as in the other areas where we are already active — California and Appalachia — so that we can draw on the expertise of staff now in place without adding significantly to operating costs.* At the same time, we're expanding the scope and size of our exploration program in Appalachia and Canada.* This approach fits nicely into Seneca's long-term growth plans of increasing our reserve-to-production ratio, providing more consistent production growth and, consequently, earnings.*

The opportunity to build our natural gas reserves in Canada came in June 2001 when our Canadian subsidiary, National Fuel Exploration Corp. (NFE), acquired Alberta-based Player Petroleum Corporation, an oil and gas exploration and development company, at a cost of approximately US$90.6 million. This acquisition also helped mitigate the gas production decline in the Gulf Coast region. Canada is an expanding source for both oil and natural gas and our Exploration and Production segment was among the first companies to recognize that potential.* It is widely held that Canadian reserves will be essential to meeting U.S. energy needs through 2010 and beyond.* Through NFE, we were fortunate to get a foot in the door at the start of the Canadian "gold rush." Today, fierce competition makes it extremely difficult to enter that energy arena.

We believe the greatest potential to fortify and build this segment's role in our value chain lies in our onshore operations in North America, where managed growth can provide more consistent returns on our investments.* With the high rate of success in our drilling programs over the past year, we are confident that the coming fiscal year will be equally productive.* Depending on fluctuations in commodity prices, our fiscal 2002 production goal of 100 Bcfe includes plans to drill over 200 wells on a proposed capital budget of $141 million.* Achieving this goal would extend our record of production growth into its seventh consecutive year.*

National Fuel Exploration Corp., a subsidiary of Seneca Resources, drilled four oil wells in northern Alberta during the winter of 2000-2001. This well, Dawson 7-16-81-15 W5M, started producing in March 2001 at a rate of 250 BOPD.

Pipeline and Storage

As a result of a return to colder weather, higher gas prices and reductions in operation and maintenance expenses, earnings for this segment of $40.4 million or $0.50 per share, were $8.8 million higher than last year's earnings of $31.6 million or $0.40 per share.

While gas prices are currently low and the immediate future of the economy is uncertain, the need for greater capacity on natural gas pipelines serving the Northeast has not diminished. Currently liquid natural gas (LNG) fills 15% of New England's annual natural gas needs and as much as 50% on very cold days. In the wake of the September 11th attacks, the Coast Guard prohibited LNG tankers from entering Boston Harbor for safety and security reasons. Although the ban has since been lifted, the security issues remain. Rising energy demands indicate that, even with continued LNG deliveries to Massachusetts and supplies from the Nova Scotia gas reserves, New England may face a shortfall of nearly 810 MMcf per day by 2005.* Additionally, if a shift in policy should curtail or eliminate the delivery of LNG at some point in the future, the region would have to turn to natural gas pipelines as an additional source of energy.* Because of our geographic proximity to this region and our participation in two proposed pipeline projects, we are in a prime position to help meet those energy needs.*

In partnership with TransCanada PipeLines Limited, our Pipeline and Storage segment is developing a plan to construct the Northwinds Pipeline project, a 215-mile, 30-inch pipeline, at an estimated cost of $375 million.* Beginning at TransCanada's facilities in Canada at Kirkwall, Ontario, this pipeline would run southeast to Lake Erie, tunnel a distance of 3.7 miles underneath Lake Erie at the beginning of the Niagara River, continue southeast primarily along National Fuel's existing pipeline right-of-way, and terminate at the Leidy Hub in Pennsylvania.* This new pipeline would provide an alternate route to move gas from various production basins, including Canada's western provinces, to the growing market on the East Coast of the United States. Subject to the approval of the Federal Energy Regulatory Commission (FERC), construction could begin as early as 2003, with the pipeline in service in 2005.*

Although we still retain a one-third interest in building the Independence Pipeline from Defiance, Ohio to the Leidy Hub, its large capacity has handicapped our efforts in finding sufficient subscribers to meet our economic criteria. Because larger diameter lines are inherently more efficient, Independence is less costly than Northwinds on a unit of throughput basis. Nevertheless, the uncertainties created by the ongoing restructuring of the local gas distribution companies has discouraged them from

National Fuel announced its partnership with a Canadian pipeline company in September 2001 to evaluate a new pipeline project called the Northwinds Pipeline to bring natural gas supplies from Canada to the United States. Prior to the announcement, the company conducted preliminary geotechnical engineering studies like this one, where samples of bedrock near the shore of Lake Erie were extracted to evaluate the feasibility of boring a tunnel through the rock underlying the lake.

As part of its continuous commitment to the safety and reliability of its pipelines, Supply Corporation conducts pigging operations, a process used to detect dents, bends and corrosion defects. By connecting a short extension pipe to the buried line, pipeline crews can insert pigging tools in the pipeline without interrupting the flow of gas. Here Supply engineer Michael Barber (right) and equipment technicians prepare to launch a high-resolution magnetic flux leakage tool into the 16-inch Line RM32 in Hamburg, N.Y.

contracting for Independence's capacity. We are hopeful that the Northwinds Pipeline, with initial capacity of approximately 500,000 Dth/day, which is half that of the proposed Independence Pipeline, will more readily attract subscribers.*

We continue to pursue projects to expand our system deliveries into the Leidy area.* During fiscal 2001 we completed negotiations on a transaction that will provide incremental transportation revenue from a $7.9 million expansion project designed to add 8,070 horsepower of compression at our Ellisburg station, a nearly 40% increase.* Once approved by the FERC, we expect construction to begin during fiscal 2002 and transportation service to commence early in fiscal 2003.* The project will enable us to move an additional 130,000 Dth/day to Leidy, Pennsylvania.*

The Pipeline and Storage segment built a direct interconnect to provide gas supplies to this 250-megawatt simple-cycle peaking power plant in Rockland, Pa. Electricity produced by this 100-percent gas-fired facility is sold into the PJM electric grid primarily during the peak electrical consumption months of June, July and August. The plant has the capability to use 2,700 Mcf/hour.

We continue to examine the efficiency of our engineering techniques regarding storage deliverability and capacity.* This is especially important because, as a result of the volatility of last winter's gas prices, we are beginning to see a resumption of the traditional pattern of summer-winter price differentials. This should increase the value of our transportation and storage assets as marketers vie for them more aggressively.*

Finally, we are engaged in negotiations with several proposed gas-fired electric generation facilities in western Pennsylvania that would sell electricity to the Pennsylvania/New Jersey/Maryland (PJM) electric grid. One facility near Rockland, Pennsylvania has been constructed and other facilities would be built adjacent to our pipeline system to take advantage of the favorable pricing on the PJM grid.*

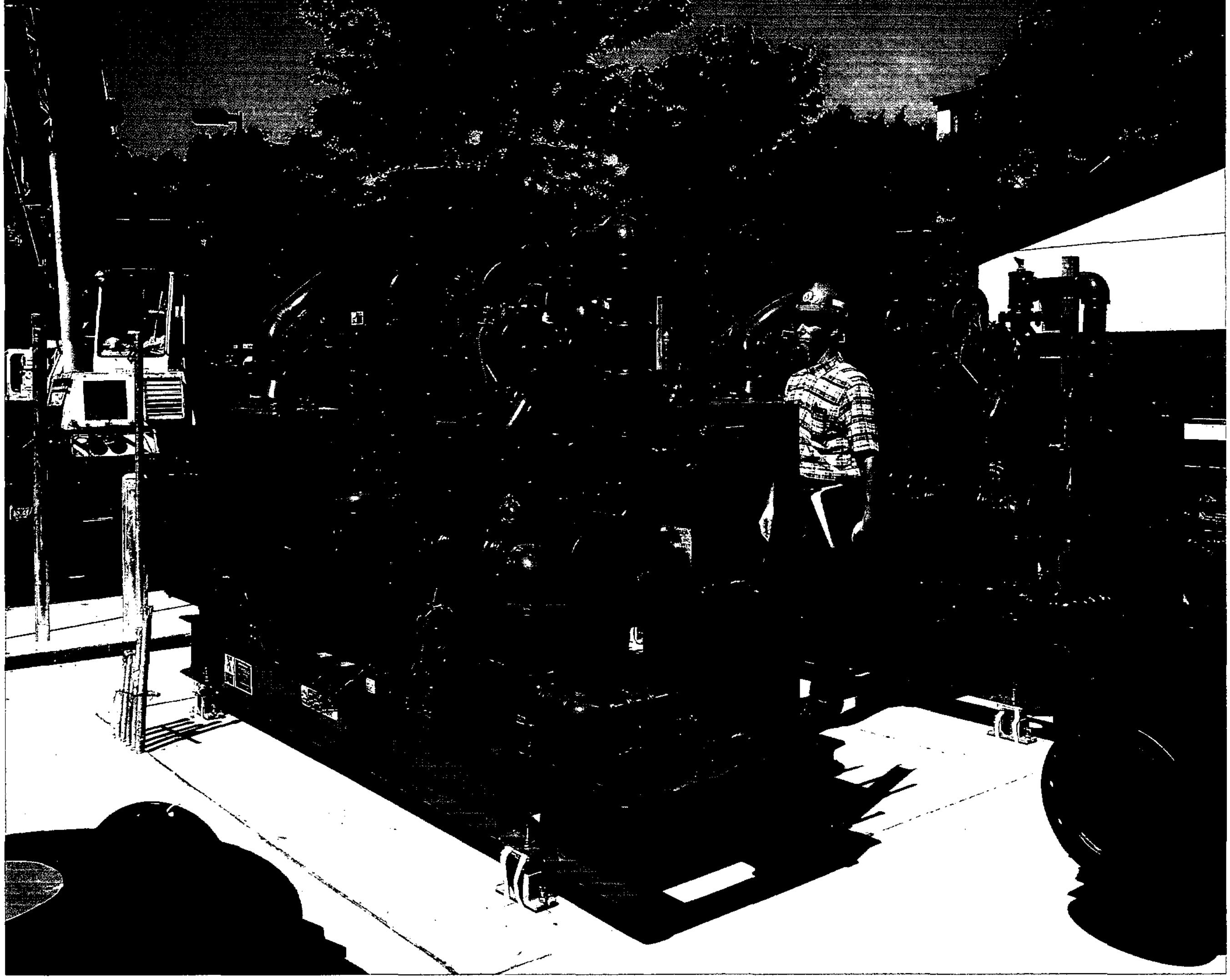
Growth doesn't always come in a big, dramatic fashion but often occurs through careful design and implementation of smaller, certain, incremental projects. This process adds to the integrity and value of the pipeline business and enables us to continue to respond to the needs of customers here in western New York, northwestern Pennsylvania and throughout the nation. The changing complexion of the natural gas industry creates many opportunities for the Pipeline and Storage segment, opportunities that, with careful planning, should provide continued consistent growth and enhance the value of our assets.*

Utility

Powdered metal plants in north-central Pennsylvania predominantly use electricity for their metal-hardening processes, but the Utility is gaining market share as more of these facilities convert to natural gas-fired equipment for delubing and sintering. Symmco Incorporated of Sykesville, Pa., producers of high-quality powdered metal components, uses 8,000 Mcf annually for the process shown here, where metal compacts are strengthened to full hardness as they pass through a 2,100° Fahrenheit chamber.

A return to colder weather in Pennsylvania, where we have no weather normalization clause, coupled with early retirement programs, and continued implementation of operational efficiencies enabled our Utility segment to contribute record earnings of $60.7 million or $0.76 per share, compared with $57.7 million or $0.73 per share last year. Through this performance, the Utility segment upheld its long-standing role as a strong, dependable link in the value chain of your Company's investments.

We realized that last year's record high natural gas prices would require special efforts to help customers in our service territories manage their energy costs. A public information campaign in our New York and Pennsylvania service areas was launched in the fall of 2000. Its multi-pronged focus included educating customers about the relationship between natural gas costs and energy bills, encouraging them to lower their energy bills through conservation and providing informa-

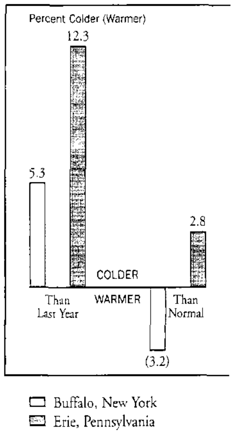


With continued pursuit of distributed generation opportunities, the Utility again partnered with Elderwood Associates, this time to install two 150-kilowatt gas engines at the Oakwood Nursing Home in Amherst, N.Y., which allow the facility to break from the power grid of the local electric utility. Here Utility employee Christopher Cej oversees the installation of these units.

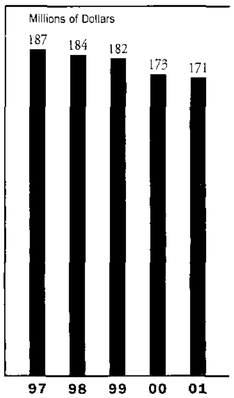
The Oakwood project also incorporates an innovative ice-storage system for the building's temperature control. At night, when the electricity demand is lower, the engines produce electricity to run an electric chiller to make ice, which is stored in these buried black, cylindrical tanks. During the day, warm water from the rooftop air conditioning units is chilled in the ice tanks and returns to the air conditioners to cool the air for the building, decreasing the electricity demand often needed by typical air conditioning systems.

In an effort to help customers manage last winter's higher-than-normal gas costs, Utility employees, like Lynda Pugh (center), volunteered to conduct energy efficiency workshops with a local home-improvement store at 31 sites throughout the New York and Pennsylvania service areas. "Savings in the Bag," a free energy conservation kit, was distributed to program attendees.

Fiscal 2001 Weather



Utility Operation and Maintenance Expense



Our meter readers, like Utility employee Joseph Cali, do their jobs in all types of weather, including snowy days in February 2001. Buffalo, N.Y. experienced its second snowiest winter in recorded history in 2000-2001, receiving 158.7 inches of snow.

tion about energy assistance programs including National Fuel's budget plan and alternative payment options. The campaign's effectiveness received community recognition and helped address many customer questions.

Despite what was one of the busiest years in our history, our customer service representatives continued to earn high marks for courtesy, knowledge, efficiency, and interest in solving the problem at hand. Overall call volume at our New York and Pennsylvania phone centers increased 15% to 3.5 million calls. Our representatives at the phone centers, at the Customer Assistance Centers and in the field provided superior service to more than 730,000 customers during an extraordinary time and are to be commended for their hard work and dedication.

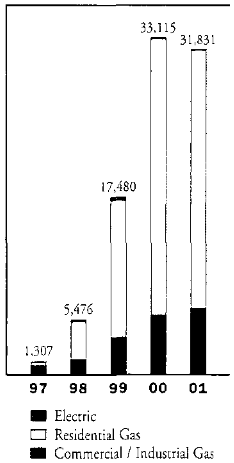
Customer service must address not only the present needs, but also the future needs of all our customers. During the past year, we worked to clear the way for greater use of alternative sources of energy to reduce the high electric rates that have hampered economic development in our western New York service territory. Some commercial and industrial customers have reported savings in energy costs of 30% to 50% by installing gas-fired electric generating equipment such as gas engines and microturbines at their facilities. However, employing this method of distributed generation as a supplemental source of energy remains impractical for most customers due to certain electric tariff restrictions. Through recent electric rate proceedings, we attempted to lift some of the tariff restrictions related to the use of gas-fired electric generation technologies by business and industry. Our efforts and those of other parties participating in that proceeding resulted in the removal of fees previously charged to individual customers who disconnect from the electric grid when using third-party electric generation. National Fuel continues to work to remove the additional fees imposed on customers who wish to generate power for only a portion of their electrical needs yet remain connected to the grid.* We are hopeful that the New York Public Service Commission will arrive at a fair compromise in this matter, which is expected to be resolved in approximately six months.*

The financial benefits of distributed electric generation for our customers and the region as a whole are obvious: it has the potential to attract and retain business and industry by reducing electric costs substantially and eliminating potential downtime due to interruption of electric service. At the same time, the switch to clean-burning natural gas provides the needed environmental benefit of cleaner air. Expanding use of this innovative method of energy production would also benefit the Utility segment because more gas would move through our system.*

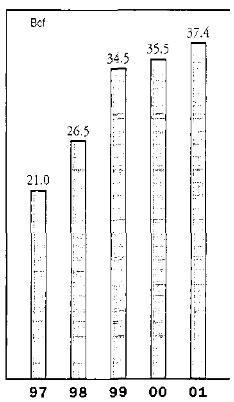
We continue to reduce operating costs through attrition, largely as the result of retirements, and to consolidate some of our facilities. Cross-training has equipped our employees to perform several different kinds of jobs, enabling them to turn their attention wherever it is needed most. The introduction of new software has added to our efficiency and we have effectively implemented measures to streamline operations without sacrificing customer service. At the same time, we continue to investigate new opportunities to use our assets even more effectively.* By doing so, we enhance the value of those resources and thus the value of your Company.*

Energy Marketing

NFR Number of Customers



Natural Gas Marketing Volumes



In fiscal 2001, this segment incurred a loss of $3.4 million or ($0.04) per share, a significantly lower loss compared to the $7.8 million loss, or ($0.10) per share, incurred in fiscal 2000. Higher natural gas revenues and volumes were offset by increased bad debt and higher interest expenses.

Under the direction of new management, this segment has identified the practices that led to recent losses. As part of this initiative, unprofitable operations in New Jersey and Massachusetts were discontinued and we no longer market electricity. In addition, more stringent credit and collection procedures are in place, and we recapitalized our debt to provide a more appropriate level of interest expense in the future.*

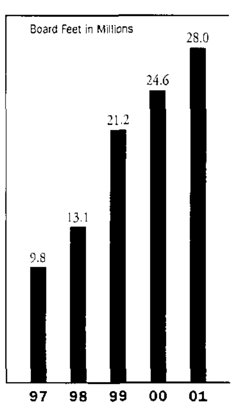
Looking ahead, our strategy is to refocus efforts on local markets, where our traditional strength in the value chain rests.* Our operating initiatives are threefold: improve margins from our existing business, increase market share and product offerings in local markets where we enjoy market leadership, and pursue revenue expansion opportunities in other markets strategically aligned with our assets and expertise.*

Implementation of these initiatives has begun. We introduced a fixed-price program to residential customers to replace the unprofitable "discount" plans offered in prior years. In addition, we are aggressively seeking to retain and add new industrial and commercial customers in western New York and northwestern Pennsylvania.* Finally, we are now focusing on the areas where we excel, including the delivery of value-added packages to benefit our customers.* One such avenue that we expect will expand in the future is our retrofitting program, which provides energy-efficient lighting to commercial establishments.*

Thus far, the results of this operating plan have been encouraging, and a return to profitability is expected in fiscal 2002.*

Timber

Timber Production



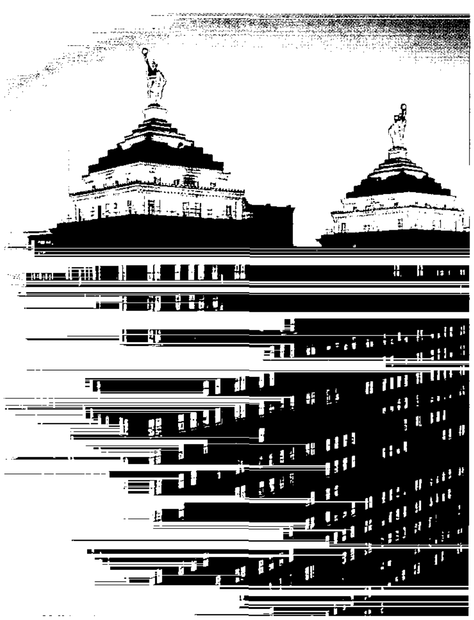
In fiscal 2001, we again expanded production to achieve a new record of 28.0 million board feet, which represents a nearly 14% increase over last year's record production. Net income increased by about 25% from $6.1 million or $.08 per share last year to $7.7 million or $0.10 per share.

Along with increasing our timber yield, we added to our covered storage area and drying capacity in order to continue to provide the finest quality cherry for lumber and veneer.

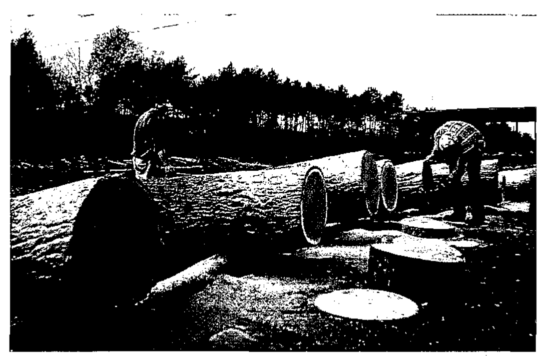
While the prices fluctuate for our secondary species, oak and maple, worldwide demand for the best quality cherry wood remains strong. The variety of hardwood trees on our properties enables us to harvest the woods that provide the best return at any given time. Our stands of timber are tangible assets that increase in value as the trees' growth currently exceeds the amount harvested.*

As noted in last year's report, we drilled a gas well on our Marienville, Pennsylvania prop-

This new warehouse in Marienville, Pa., was completed in March 2001 and added 180,000 board feet of storage capacity for the Timber segment. Including this new facility, Highland can now store approximately 750,000 board feet of a variety of dry lumber species before they are sold for use in furniture, flooring, hardwood trim and other woodworking.



The Liberty Building in downtown Buffalo, N.Y. underwent a lighting retrofit this year – a new service offered by our Energy Marketing segment. National Fuel Resources helps building managers determine energy savings potential from replacing existing lights with more energy-efficient lighting retrofits.



Highland employee Joseph Plummer, left, scales red oak veneer logs with a potential buyer at the Marienville Mill. Veneer logs, especially cherry, are very profitable for the Timber segment and are sold domestically to mills in Ohio, Indiana and West Virginia, and internationally in Europe (Germany, France, Italy) and Canada.

erty which is used to power the on-site lumber-drying kiln. This well helped keep our operating expenses low during fiscal 2001 when gas prices soared during the winter months.

The Timber segment operations fit well in our strategy of providing consistent growth, steady and increasing earnings, and value to your Company.*

International

As we previously reported to you, we believe that our electricity and heat production assets in the Czech Republic are of high quality and provide basic necessities for the evolving market-based economies of Eastern Europe.*

Our efforts to improve revenues and margins were put to the test this year by regulatory, economic, natural and market forces. This year, the scheduled retirement of one of our generating turbines contributed to our lower electric volumes, warmer weather lowered demand for our heating volumes, higher operating and maintenance expense (primarily related to project development costs), and higher interest expense contributed to this segment's loss of $3.0 million or ($0.04) per share.

The successful merger of two of our Czech Republic entities under the corporate name of United Energy, a.s. was accomplished last year. The combined entity has realized cost savings associated with a more compact and efficiently organized company. Furthermore, we successfully negotiated coal supply contracts at 1999 prices, thereby capping our largest operating expense. The construction program designed to bring all of our coal-fired boilers into environmental compliance is nearly complete. This will result in 10 efficient boilers to fuel our heating and electric production requirements far into the future while minimizing future capital expenditures.*

Long-term growth will not come from cost savings alone. We are focused on the revenue line and expect that a number of factors, including the Czech government's sale of its stakes in energy generation, transmission and distribution, and increasing demand for electric generation as Eastern European economies improve, will positively influence revenues and margins.* As we focus on efficient operations and higher value markets, we are not content to remain passive with respect to new investments.* Our project development group is working on new opportunities in the region, including very promising prospects currently in development in both Italy and Bulgaria.* Our aim is to deliver value from our existing facilities and produce earnings growth through judicious investment in new energy production assets in Europe.*

Workers assemble the upper section of a bubbling fluidized bed boiler being constructed in Komořany, Czech Republic for United Energy, a.s. This boiler will complete the environmental upgrade of this facility, which consists of five 125-tonnes-per-hour and five 140-tonnes-per-hour bubbling fluidized bed boilers, and meets new clean air standards. The plant burns local brown coal to produce heat and power.

Other Business

America's growing energy needs provide opportunities for development and marketing of domestic electric generation. Our subsidiary Horizon Power (formerly NFR Power) is involved in several profitable domestic power ventures, bringing our total generating capacity to nearly 100 megawatts. Approximately 18 megawatts of that capacity come from two landfill gas-powered generation projects; our newest one near Lewiston, New York provides 5.6 megawatts of generating capacity, and the other, near Seneca Falls, New York, was acquired last year, and provides 11.2 megawatts of generating capacity.

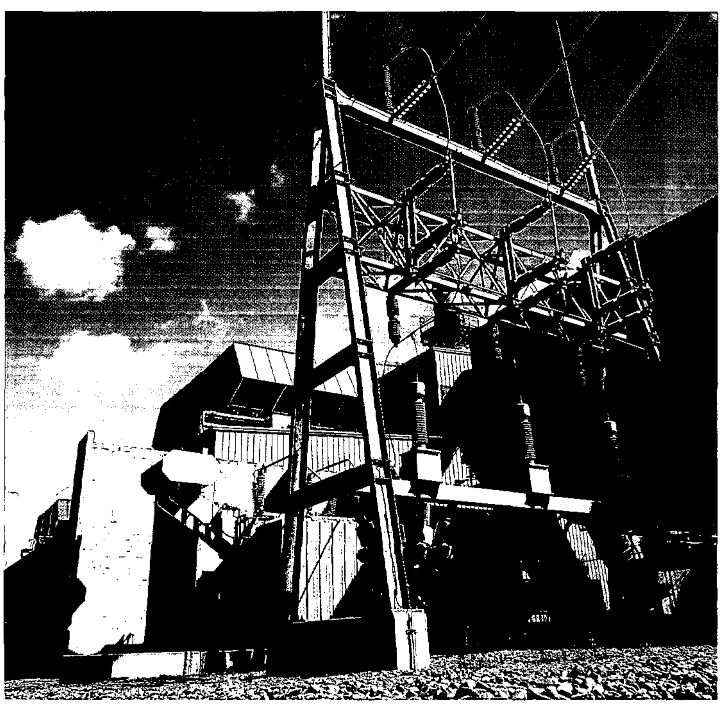
The remaining 80 megawatts of generating capacity are related to our 50% stake in a gas-fired cogeneration plant located near North East, Pennsylvania. This plant provides peak electric generation during the summer months and also provides thermal energy to an adjoining grape processing plant.

Our acquisition of the these plants allows us to not only harness landfill gas and transform it into valuable energy, but also to take advantage of special "green power" price and tax incentives. We believe we can expand our asset base through development and acquisition of additional facilities throughout the United States, thus increasing the size and strength of this new link in our value chain.*

Management Changes

The Board of Directors of National Fuel Gas Company elected Philip C. Ackerman to succeed Bernard J. Kennedy as Chief Executive Officer effective October 1, 2001, and as Chairman of the Board, effective January 3, 2002.

Other important changes included the promotion of Anna Marie Cellino, Ronald J. Tanski and James D. Ramsdell to Senior Vice President of National Fuel Gas Distribution Corporation, and John R. Pustulka to Senior Vice President of National Fuel Gas Supply Corporation. Gerald T. Wehrlin became President and Donna L. DeCarolis was appointed Vice President of National Fuel Resources, Inc. Bruce H. Hale became President of Horizon Power, Inc. Thomas L. Atkins was named Treasurer and Assistant Secretary of Seneca Resources Corporation,



Horizon Power owns a 50-percent interest in an 80-megawatt combined-cycle natural-gas-fired power plant in North East, Pa., which it jointly acquired in April 2001. The plant provides electric power to the New York Independent System Operator, a power pool that coordinates the supply of electricity to customers in and near New York State. In addition, this plant supplies steam, a byproduct, to an adjoining grape processing plant.

and Ronald C. Kraemer was appointed Assistant Vice President of Horizon Energy Development, Inc. Lastly, after many years of dedicated service, Calvin H. Friedrich retired as Treasurer of Seneca Resources Corporation and William A. Ross retired as Vice President of National Fuel Gas Supply Corporation.

The people who represent National Fuel and its subsidiaries make significant contributions to the quality of life in each of their communities. By supporting nearly 250 social, educational, environmental and health-related organizations, our employees participate in countless events that continually aid a variety of causes. Their initiative reflects the American spirit of neighbors helping neighbors and demonstrates only one way that our workforce provides yet another strong link in our value chain. This is the same spirit that helps our Company and our communities thrive.

National Fuel will mark its 100th anniversary in 2002. We approach our second century full of enthusiasm for the prospects before us. You, our shareholders, have a stake in both our earnings and the innovative ways in which National Fuel is working to meet our country's energy needs for the future. We know that physical assets alone are not the only measure of a company's strength, but intangible assets, such as the skills and commitment inherent in its employees, its location relative to its market, or the income stream built from a strong dividend history, also define its value. These extraordinary resources should be viewed as nothing less than the underlying bond that gives National Fuel's value chain its true strength.

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 the 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."

Philip C. Ackerman
President and Chief Executive Officer

Bernard J. Kennedy
Chairman of the Board

December 13, 2001

A MESSAGE FROM BERNARD KENNEDY

Over the past few years, Phil Ackerman and I have co-authored this letter, but since this is my last letter I thought it appropriate to share a few thoughts with you. Rather than reflect on our past successes, I would much rather write a few words regarding the future and the people who will be running your Company.

I have never ceased to marvel at our good fortune in acquiring the human resources that have enabled us to meet the series of tests and hurdles which confronted us over the last five decades. Every CEO hopes to pass along to his successor a cadre and staff who can face up to the challenges ahead. I know ours can. Our employees are unquestionably our strongest link. Each has special and diverse skills and talents that complement the strengths and talents of the others.

Together these professionals comprise a formidable bank of expertise now directed by an individual in whom I have long had absolute confidence and, frankly, considerable pride. Phil is a unique talent and unquestionably the person best suited to lead this Company into the 21st century. He is steeped in the lore of both the industry and the Company, and knows intimately its needs and potentials better than anyone else. I firmly believe that our new leadership will continue in unbroken stride that journey to growth and profitability which we began almost two decades ago.

***Ave Atque Vale!* This was a phrase the Romans used to say "hail and farewell," "hello and goodbye." They recognized the brevity of human experiences. I salute their perception. In looking back on my own service at National Fuel, it seems so fleetingly brief. Leading this Company has been a marvelous, challenging, and rewarding experience, and I've literally enjoyed every moment of it. I am grateful for the honor, for your constant support and above all, for the opportunity to help build this Company.**

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, 2001

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.)
10 Lafayette Square **Buffalo, New York** (Address of principal executive offices)	**14203** (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 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. [✔]

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $1,759,487,000 as of November 30, 2001.

Common Stock, $1 Par Value, outstanding as of November 30, 2001: 79,480,675 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Annual Report to Shareholders for 2001 are incorporated by reference into Part I of this report. Portions of the registrant's definitive Proxy Statement for the Annual Meeting of Shareholders to be held February 21, 2002 are incorporated by reference into Part III of this report.

Contents

Part I

Part II

Part III

Part IV

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, Management's Discussion and Analysis of Financial Condition and Results of Operations (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), a holding company registered under the Public Utility Holding Company Act of 1935, as amended (the Holding Company Act), was organized under the laws of the State of New Jersey in 1902. The Company is engaged in the business of owning and holding securities issued by its twelve directly owned subsidiary companies. Except as otherwise indicated below, the Company 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 six 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 732,000 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 by Seneca Independence Pipeline Company (SIP), a Delaware corporation. Supply Corporation provides interstate natural gas transportation and storage services for affiliated and nonaffiliated companies through (i) an integrated gas pipeline system extending from southwestern Pennsylvania to the New York-Canadian border at the Niagara River and (ii) 27 underground natural gas storage fields owned and operated by Supply Corporation as well as four other underground natural gas storage fields operated jointly with various other interstate gas pipeline companies. SIP holds a one-third general partnership interest in Independence Pipeline Company (Independence), a Delaware general partnership proposing to construct and operate a 400-mile pipeline to transport natural gas from Defiance, Ohio to Leidy, Pennsylvania (the Independence Pipeline).
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 the Gulf Coast region of Texas and Louisiana, in California, in Wyoming, and in the Appalachian region of the United States. Also, exploration and production operations are conducted in the provinces of Manitoba, Alberta and Saskatchewan in Canada by Seneca's wholly-owned subsidiary, National Fuel Exploration Corp. (NFE), an Alberta, Canada corporation.
4. The International segment operations are carried out by Horizon Energy Development, Inc. (Horizon), a New York corporation. Horizon engages in foreign and domestic energy projects through investments as a sole or substantial owner in various business entities. These entities include 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 whose principal assets are majority ownership of (i) United Energy, a.s. (UE), a wholesale power and district heating company located in the northern part of the Czech Republic, and (ii) Teplárna Kroměříž, a.s. (TK), a district heating company located in the southeast region of the Czech Republic.
5. The Energy Marketing segment operations are carried out by National Fuel Resources, Inc. (NFR), a New York corporation engaged in the marketing and brokerage of natural gas and the performance of energy management services for industrial, commercial, public authority and residential end-users in the northeastern United States.

6. The Timber segment operations are carried out by Highland Forest Resources, Inc. (Highland), a Pennsylvania 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 four sawmill operations in northwestern Pennsylvania and processes timber consisting primarily of high quality hardwoods.

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 wholly-owned subsidiaries are not included in any of the six reportable business segments and consist of the following:

• Upstate Energy Inc. (Upstate), a New York corporation engaged in wholesale natural gas marketing and other energy-related activities;

• Niagara Independence Marketing Company (NIM), a Delaware corporation which owns a one-third general partnership interest in DirectLink Gas Marketing Company (DirectLink), a Delaware general partnership. DirectLink was formed to engage in natural gas marketing and related businesses in part by subscribing for firm transportation capacity on the proposed Independence Pipeline (see Pipeline and Storage segment discussion below);

• Leidy Hub, Inc. (Leidy), 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; and

• Horizon Power, Inc. (Horizon Power), a New York corporation formerly known as NFR Power, Inc., which is designated as an "exempt wholesale generator" under the Holding Company Act and is developing or operating mid-range independent power production facilities.

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2001.

Rates and Regulation

The Company is subject to regulation by the Securities and Exchange Commission (SEC) under the broad regulatory provisions of the Holding Company Act, including provisions relating to issuance of securities, sales and acquisitions of securities and utility assets, intra-Company transactions and limitations on diversification. The SEC and some members of Congress have advocated, on either a stand-alone basis or in conjunction with legislation which would deregulate the electric industry, the repeal of the Holding Company Act. Thus far, the proposed legislation would transfer certain oversight responsibilities to the various state public utility regulatory commissions and the Federal Energy Regulatory Commission (FERC) and would expand the access of these bodies to the books and records of companies in a holding company system. The proposed legislation could increase regulation, especially at the state level.* By contrast, previous SEC rule changes have reduced the number of applications required to be filed under the Holding Company Act, exempted some routine financings and expanded diversification opportunities. The Company is unable to predict at this time what the ultimate outcome of legislative or regulatory changes will be and, therefore, what impact such efforts might have on the Company.*

The Utility segment's rates, services and other matters are regulated by the State of New York Public Service Commission (NYPSC) with respect to services provided within New York and by the Pennsylvania Public Utility Commission (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 regulated by the FERC. SIP is not itself regulated by the FERC, but its sole business is the ownership of an interest in Independence, whose construction, rates, services and other matters are or will be regulated by the FERC. For additional discussion of the Pipeline and Storage segment's rates and regulation, see Item 7, MD&A under the heading "Rate Matters" and Item 8 at Note B-Regulatory Matters.

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 the International segment, rates charged for the sale of thermal energy and electric energy at the retail level are subject to regulation and audit in the Czech Republic by the Czech Ministry of Finance. The regulation of electric energy rates at the retail level indirectly impacts the rates charged by the International segment for its electric energy sales at the wholesale level.

In addition, the Company and its subsidiaries are subject to the same federal, state and local regulations on various subjects as other companies doing similar business in the same locations.

The Utility Segment

The Utility segment contributed approximately 35.8% of the Company's 2001 net income available for common stock, exclusive of the Exploration and Production segment's non-cash asset impairment.

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 23.8% of the Company's 2001 net income available for common stock, exclusive of the Exploration and Production segment's non-cash asset impairment.

Supply Corporation currently has service agreements for substantially all of its firm transportation capacity, which totals approximately 2,036 thousand dekatherms (MDth) per day. The Utility segment accounts for approximately 1,179 MDth per day or 57.9% of the total capacity, and the Energy Marketing segment represents another 70 MDth per day or 3.5% of the total capacity. The remaining 787 MDth or 38.6% of Supply Corporation's firm transportation capacity is subject to firm contracts with nonaffiliated customers.

Supply Corporation has available for sale approximately 67,843 MDth of firm storage capacity. The Utility segment has contracted for 31,395 MDth or 46.3% of the total capacity and the Energy Marketing segment accounts for another 4,305 MDth or 6.3% of the total capacity. Nonaffiliated customers have contracted for the remaining 32,143 MDth or 47.4% of the firm storage capacity. Supply Corporation has been successful in marketing and obtaining executed contracts for storage service (at discounted rates) as it becomes available and expects to continue to do so.*

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 42.3% of the Company's 2001 net income available for common stock, exclusive of this segment's non-cash asset impairment.

In June 2001, Seneca, through its wholly-owned subsidiary, NFE, acquired the stock of Player Petroleum Corporation (Player), an oil and gas exploration and development company, with operations based primarily in the Province of Alberta, Canada.

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 International Segment

The International segment incurred a net loss in 2001. The impact of this segment's net loss in relation to the Company's 2001 net income available for common stock, exclusive of the Exploration and Production segment's non-cash asset impairment, was negative 1.8%.

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

The Energy Marketing Segment

The Energy Marketing segment incurred a net loss in 2001. The impact of this segment's net loss in relation to the Company's 2001 net income available for common stock, exclusive of the Exploration and Production segment's non-cash asset impairment, was negative 2.0%.

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 4.6% of the Company's 2001 net income available for common stock, exclusive of the Exploration and Production segment's non-cash asset impairment.

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 2001. The impact of this net loss in relation to the Company's 2001 net income available for common stock, exclusive of the Exploration and Production segment's non-cash asset impairment, was 2.7%.

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

Sources and Availability of Raw Materials

Natural gas is the principal raw material for the Utility segment. In 2001, the Utility segment purchased 117.3 billion cubic feet (Bcf) of gas. Gas purchases from various producers and marketers in the southwestern United States and Canada under long-term (two years or longer) contracts accounted for 63% of these purchases. Purchases of gas on the spot market (contracts of less than a year) accounted for 34% of the Utility segment's 2001 gas purchases. Gas purchases from Dynegy Marketing and Trade and BP Energy Co. (both providing gas from the southwestern United States under long-term contracts) represented 23% and 13%, respectively, of total 2001 gas purchases by the Utility segment. No other producer or marketer provided the Utility segment with 10% or more of its gas requirements in 2001.

Supply Corporation transports and stores gas owned by its customers, whose gas originates in the southwestern and Appalachian regions of the United States as well as in Canada. SIP, through Independence, proposes to transport natural gas produced in Canada and in the continental United States. Additional discussion of proposed pipeline projects appears below 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 Notes I-Business Segment Information and M - Supplementary Information for Oil and Gas Producing Activities.

Coal is the principal raw material for the International segment, constituting 50% of the cost of raw materials needed in 2001 to operate the boilers which produce steam or hot water. Natural gas, oil, limestone and water combined accounted for the remaining 50% of such materials. Coal is purchased and delivered directly from the Mostecka Uhelna Spolecnost, a.s. mine for Horizon's largest coal-fired plant under a contract where price and quantity are the subject of negotiation each year. Based on the current extraction rate, this mine has proven reserves through 2030. The Czech Republic government imports natural gas from sources in Russia and the North Sea and transports the gas through its majority-owned Transgas pipeline system. The International segment purchases natural gas from two of the eight regional gas distribution companies in the Czech Republic. The Czech Republic government also imports oil. The International segment purchases oil from domestic and foreign refineries.

With respect to the Timber segment, Highland requires an adequate supply of timber to process in its sawmill and kiln operations. Seventy percent of the timber processed comes from land owned by Seneca; therefore, the source and availability of this segment's primary raw material are generally known in advance.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2001, this segment purchased 39.7 Bcf of natural gas.

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 continuing deregulation of the natural gas industry should enhance the competitive position of natural gas relative to other energy sources, such as fuel oil or electricity, by removing some of the regulatory impediments to adding customers and responding to market forces.* In addition, the environmental advantages of natural gas compared with other fuels should increase the role of natural gas as an energy source.* Moreover, while demand for natural gas is increasing, the production of natural gas also continues to increase making it a dependable alternative to imported oil.*

The electric industry is moving toward a more competitive environment as a result of the Federal Energy Policy Act of 1992 and initiatives undertaken by the FERC and various states. It is unclear at this point what impact this restructuring will have on the Company.*

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 gas industry in Order No. 636 are redefining the roles of the gas utility industry and the state regulatory commissions. Regulators in both New York and Pennsylvania have adopted retail competition for natural gas supply purchases. However, the Utility segment's traditional distribution function remains largely unchanged. For further discussion of state restructuring initiatives refer to Item 7, MD&A under the heading "Rate Matters."

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 is now better able to compete, 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 northeastern 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.*

Supply Corporation and TransCanada Pipelines Limited together are pursuing a proposal to construct a pipeline to transport natural gas from Kirkwall, Ontario to the storage and market hub at Leidy, Pennsylvania. This project, called the Northwinds Pipeline, is competing for customers with other proposed pipeline projects that would bring natural gas from Canada to the growing markets in the northeast and mid-Atlantic regions of the United States. Similarly, SIP, through Independence, is competing for customers with other proposed pipeline projects that would bring natural gas from the Chicago area to the northeast and mid-Atlantic regions of the United States. In combination with expansion projects of Transcontinental Gas Pipe Line Corporation and ANR Pipeline Company, Independence intends to provide a service that will access the storage and market hub at Leidy, Pennsylvania.* It is likely that not all of the proposed pipelines will go forward, and that the first project built will have an advantage over other proposed projects.* If completed, the Independence pipeline and the Northwinds Pipeline would likely create opportunities for increased transportation and storage services by Supply Corporation.* For further discussion of the Independence Pipeline and the Northwinds Pipeline projects, 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 gas and oil producers and marketers with respect to sales of oil and gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other oil and natural gas exploration and production companies of various sizes for leases and drilling rights for exploration and development prospects.

To compete in this environment, Seneca and its wholly-owned subsidiary, NFE, each originate and act as operator on most prospects, minimize risk of exploratory efforts through partnership-type arrangements, apply the latest technology for both exploratory studies and drilling operations, and focus on market niches that suit their size, operating expertise and financial criteria.

Competition: The International Segment

Horizon competes with other entities seeking to develop and/or acquire foreign and domestic energy projects. Horizon, through UE, faces competition in the sale of thermal energy to large industrial customers. In addition, UE faces competition in the sale of electricity to the regional electric distribution company. A large percentage of the electricity purchased by the regional electric distribution companies is produced by the Czech Republic's dominant state-owned energy producer. The Czech cabinet approved a plan put forward by the Ministry of Industry and Trade to privatize this producer and six regional electricity distributors. It is unclear at this point what impact this privatization will have on the wholesale electric energy market.* UE sells electricity at the wholesale level.

Competition: The Energy Marketing Segment

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy management services. Although the deregulation of natural gas utilities is a relatively new occurrence, the competition in this area is well developed with regard to price and services and derives 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, saw logs or export logs ultimately used in the production of high-end furniture, cabinetry and flooring. The Timber segment markets 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 on the Utility segment in New York is mitigated by a weather normalization clause which 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.

Volumes transported and stored by Supply Corporation may vary materially depending on weather, without materially affecting its earnings. Supply Corporation's 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 only to reimburse the variable costs caused by actual transportation or storage of gas.

Variations in weather conditions can materially affect the volume of gas consumed by customers of the Energy Marketing segment and the amount of thermal energy consumed by the heating customers of the International segment.

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

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 H-Commitments and Contingencies.

Miscellaneous

The Company and its wholly-owned subsidiaries had a total of 3,235 full-time employees at September 30, 2001, with 2,244 employees in all of its U.S. operations and 991 employees in its international operations. This is a decrease of 10% from the 3,597 total employed at September 30, 2000.

Agreements covering employees in collective bargaining units in New York were renegotiated in November 2000, effective beginning November 26, 2000, and are scheduled to expire in February 2006. Agreements covering most employees in collective bargaining units in Pennsylvania were renegotiated, effective November 1998, and are scheduled to expire in April and May 2003.

The Company 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 Company renews such franchises.

Executive Officers of the Company as of November 15, 2001[1]

On September 19, 2001, the Board of Directors elected Philip C. Ackerman as Chief Executive Officer of the Company, effective October 1, 2001. Mr. Ackerman joined the Company in 1968 and has served as President since July 1999, as a Director since 1994 and as Chief Financial Officer since 1981. Mr. Ackerman succeeds Bernard J. Kennedy as Chief Executive Officer. Mr. Kennedy will continue to serve as Chairman of the Board of Directors until January 2, 2002 and as a Director thereafter. Mr. Kennedy has also agreed to serve as a consultant to the Company for 30 months commencing January 2, 2002. On December 13, 2001 the Board of Directors elected Philip C. Ackerman as Chairman of the Board effective January 3, 2002.

Name and Age [2]	Current Company Positions and Other Material Business Experience During Past Five Years [3]
Bernard J. Kennedy (70)	Chairman of the Board of Directors since March 1989. Mr. Kennedy has served as a Director since March 1978 and previously served as Chief Executive Officer from August 1988 to October 2001 and as President from January 1987 to July 1999.
Philip C. Ackerman (57)	Chief Executive Officer since October 2001; President since July 1999; Executive Vice President of Supply Corporation since October 1994; 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.
Dennis J. Seeley (58)	President of Supply Corporation since March 2000. Mr. Seeley has served as Vice President of the Company from January 2000 to April 2000, Senior Vice President of Distribution Corporation from February 1997 to March 2000 and Senior Vice President of Supply Corporation from January 1993 to February 1997.
David F. Smith (48)	President of Distribution Corporation since July 1999. Mr. Smith served as Senior Vice President of Distribution Corporation from January 1993 to July 1999.
James A. Beck (54)	President of Seneca since October 1996 and President of Highland since March 1998. Mr. Beck previously served as Vice President of Seneca from January 1994 to April 1995 and Executive Vice President of Seneca from May 1995 to September 1996.
Gerald T. Wehrlin (63)	President of NFR since May 2001; Controller of the Company since December 1980; and Vice President of Horizon since February 1997. Mr. Wehrlin previously served as Senior Vice President of Distribution Corporation from April 1991 to May 2001 and as Secretary and Treasurer of Horizon from September 1995 to February 1997.
Bruce H. Hale (52)	President of Horizon Power since March 2001; Senior Vice President of Supply Corporation since February 1997; and Vice President of Horizon since September 1995. Mr. Hale previously served as Senior Vice President of Distribution Corporation from January 1993 to February 1997.
Joseph P. Pawlowski (60)	Treasurer since December 1980; Senior Vice President of Distribution Corporation since February 1992 and Treasurer of Distribution Corporation since January 1981; Treasurer of Supply Corporation since June 1985; and Secretary of Supply Corporation since October 1995.
Walter E. DeForest (60)	Senior Vice President of Distribution Corporation since August 1993; and Senior Vice President of Supply Corporation from January 1992 to August 1993.
Anna Marie Cellino (48)	Senior Vice President of Distribution Corporation since July 2001; Vice President of Distribution Corporation from June 1994 to July 2001; and Secretary of the Company since October 1995.
Ronald J. Tanski (49)	Senior Vice President of Distribution Corporation since July 2001; Controller of Distribution Corporation since February 1997; Secretary and Treasurer of Horizon since February 1997; and Vice President of Distribution Corporation from April 1993 to July 2001.
John R. Pustulka (49)	Senior Vice President of Supply Corporation since July 2001; and Vice President of Supply Corporation from April 1993 to July 2001.
James D. Ramsdell (46)	Senior Vice President of Distribution Corporation since July 2001; and Vice President of Distribution Corporation from June 1994 to July 2001.

(1) The Company has been advised that there are no family relationships among any of the officers listed, and that there is no arrangement or understanding among any one of them and any other persons pursuant to which he or she was elected as an officer. The executive officers serve at the pleasure of the Board of Directors.
(2) Ages are as of September 30, 2001.
(3) The information provided relates to the principal subsidiaries of the Company. Many of the executive officers have served or currently serve as officers or directors for other subsidiaries of the Company.

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, 2001. Approximately 51% of this investment was in the Utility and Pipeline and Storage segments, which are primarily located in western New York and northwestern Pennsylvania. The Exploration and Production segment, which is the next largest investment in net property, plant and equipment (39%), is primarily located in the Gulf Coast region of Texas and Louisiana, in California, in Wyoming, in the Appalachian region of the United States and in the provinces of Manitoba, Alberta and Saskatchewan in Canada. The remaining investment in net property, plant and equipment consisted primarily of the International segment (6%) which is located in the Czech Republic and the Timber segment (4%) which is located primarily in northwestern Pennsylvania. During the past five years, the Company has made significant additions to property, plant and equipment in order to expand and improve transmission and distribution facilities for both retail and transportation customers, to augment the reserve base of oil and gas in the United States and Canada, and to purchase district heating and power generation facilities in the Czech Republic. Net property, plant and equipment has increased $1.071 billion, or 63%, since 1996.

The Utility segment had a net investment in property, plant and equipment of $945.7 million at September 30, 2001. The net investment in its gas distribution network (including 14,778 miles of distribution pipeline) and its services represent approximately 57% and 29%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2001.

The Pipeline and Storage segment had a net investment of $483.2 million in property, plant and equipment at September 30, 2001. Transmission pipeline, with a net cost of $138.1 million, represents 29% of this segment's total net investment and includes 2,543 miles of pipeline required to move large volumes of gas throughout its service area. Storage facilities consist of 31 storage fields, four of which are jointly operated with certain pipeline suppliers, and 446 miles of pipeline. Net investment in storage facilities includes $87.2 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 29 compressor stations with 75,006 installed compressor horsepower.

The Exploration and Production segment had a net investment in property, plant and equipment of $1.082 billion at September 30, 2001. Of this amount, $828.3 million relates to properties located in the United States. The remaining net investment of $253.4 million relates to properties located in Canada.

The International segment had a net investment in property, plant and equipment of $178.2 million at September 30, 2001. This represents UE's net investment in district heating and electric generation facilities.

The Timber segment had a net investment in property, plant and equipment of $90.5 million at September 30, 2001. Located primarily in northwestern Pennsylvania, the net investment includes four sawmills and approximately 150,000 acres of timber.

The Utility and Pipeline and Storage segments' facilities provided the capacity to meet its 2001 peak day sendout, including transportation service, of 1,659 million cubic feet (MMcf), which occurred on December 22, 2000. Withdrawals from storage of 749.4 MMcf provided approximately 45.2% of the requirements on that day.

Company maps are included on the back of the front cover and page 1 of the Annual Report to Shareholders and are incorporated herein by reference.

Exploration and Production Activities

The information that follows is disclosed in accordance with SEC regulations, and relates to the Company's oil and gas producing activities. A further discussion of oil and gas producing activities is included in Item 8, Note M-Supplementary Information for Oil and Gas Producing Activities. Note M sets forth proved developed and undeveloped reserve information for Seneca. Seneca's oil and gas reserves reported in Note M as of September 30, 2001 were estimated by Seneca's qualified 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). The basis of reporting Seneca's reserves to the EIA is identical to that reported in Note M.

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	2001	2000	1999
United States			
Average Sales Price per Mcf of Gas (1)	**$5.53**	$3.31	$2.20
Average Sales Price per Barrel of Oil (1)	**$25.43**	$25.34	$12.85
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$0.55**	$0.51	$0.46
Canada			
Average Sales Price per Mcf of Gas (1)	**$2.41**	$2.52	—
Average Sales Price per Barrel of Oil (1)	**$24.29**	$29.28	—
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$1.34**	$1.41	—
Total			
Average Sales Price per Mcf of Gas (1)	**$5.39**	$3.31	$2.20
Average Sales Price per Barrel of Oil (1)	**$24.99**	$26.03	$12.85
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	**$0.73**	$0.58	$0.46

(1) Prices do not reflect gains or losses from hedging activities.

PRODUCTIVE WELLS

		United States		Canada		Total	
At September 30, 2001		Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells	– gross	**1,964**	**950**	**188**	**979**	**2,152**	**1,929**
	– net	**1,815**	**875**	**121**	**833**	**1,936**	**1,708**

DEVELOPED AND UNDEVELOPED ACREAGE

At September 30, 2001		United States	Canada	Total
Developed Acreage	– gross	**646,957**	**152,491**	**799,448**
	– net	**568,652**	**104,206**	**672,858**
Undeveloped Acreage	– gross	**926,022**	**981,065**	**1,907,087**
	– net	**669,250**	**929,460**	**1,598,710**

DRILLING ACTIVITY

For the Year Ended September 30		Productive 2001	Productive 2000	Productive 1999	Dry 2001	Dry 2000	Dry 1999
United States							
Net Wells Completed	– Exploratory	**11.83**	13.89	12.95	**4.93**	6.53	5.64
	– Development	**108.60**	82.82	95.26	**1.00**	1.00	4.75
Canada							
Net Wells Completed	– Exploratory	**10.00**	1.00	—	**11.00**	—	—
	– Development	**61.14**	21.50	—	**2.75**	4.00	—
Total							
Net Wells Completed	– Exploratory	**21.83**	14.89	12.95	**15.93**	6.53	5.64
	– Development	**169.74**	104.32	95.26	**3.75**	5.00	4.75

PRESENT ACTIVITIES

At September 30, 2001		United States	Canada	Total
Wells in Process of Drilling	– gross	**61.00**	**46.00**	**107.00**
	– net	**56.90**	**42.15**	**99.05**

South Lost Hills Waterflood Program

In Seneca's South Lost Hills Field, a waterflood project was initiated in 1996 on the Ellis lease in the Diatomite reservoir for pressure maintenance and recovery enhancement purposes. Currently there are 19 injection wells and 89 production wells in the program. The total injection and production from this waterflood project are 2,400 barrels of water per day and 260 barrels of oil per day, respectively.

ITEM 3 Legal Proceedings

For a discussion of various environmental matters, refer to Item 7, MD&A under the heading "Other Matters" and to Item 8 at Note H-Commitments and Contingencies.

ITEM 4 Submission of Matters to a Vote of Security Holders

No matter was submitted to a vote of security holders during the fourth quarter of 2001.

Part II

ITEM 5 Market for the Registrant's Common Stock and Related Shareholder Matters

Information regarding the market for the Company's common stock and related shareholder matters appears under Item 8 at Note D-Capitalization and Note L-Market for Common Stock and Related Shareholder Matters (unaudited).

On July 2, 2001, the Company issued 1,680 unregistered shares of Company common stock to the seven non-employee directors of the Company, 240 shares to each such director. These shares were issued as partial consideration for the directors' service as directors during the quarter ended September 30, 2001, 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 any public offering.

ITEM 6 Selected Financial Data

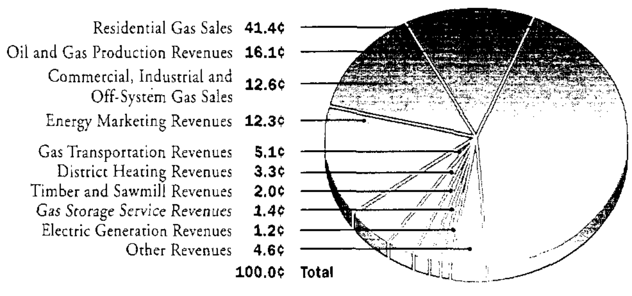
Year Ended September 30	2001	2000	1999	1998	1997
Summary of Operations *(Thousands)*					
Operating Revenues	**$2,100,352**	$1,425,277	$1,263,274	$1,248,000	$1,265,812
Operating Expenses:					
Purchased Gas	**1,045,805**	503,617	405,925	441,746	528,610
Fuel Used in Heat and Electric Generation	**54,968**	54,893	55,788	37,837	1,489
Operation and Maintenance	**364,318**	350,383	328,800	321,411	286,537
Property, Franchise and Other Taxes	**83,730**	78,878	91,146	92,817	100,549
Depreciation, Depletion and Amortization	**174,914**	142,170	124,778	117,238	111,650
Impairment of Oil and Gas Producing Properties	**180,781**	—	—	128,996	—
Income Taxes	**37,106**	77,068	64,829	24,024	68,674
	1,941,622	1,207,009	1,071,266	1,164,069	1,097,509
Operating Income	**158,730**	218,268	192,008	83,931	168,303
Other Income	**15,256**	10,408	12,343	35,870	3,196
Income Before Interest Charges and Minority Interest in Foreign Subsidiaries	**173,986**	228,676	204,351	119,801	171,499
Interest Charges	**107,145**	100,085	87,698	85,284	56,811
Minority Interest in Foreign Subsidiaries	**(1,342)**	(1,384)	(1,616)	(2,213)	—
Income Before Cumulative Effect	**65,499**	127,207	115,037	32,304	114,688
Cumulative Effect of Change in Accounting	**—**	—	—	(9,116)	—
Net Income Available for Common Stock	**$65,499**	$127,207	$115,037	$23,188	$114,688
Per Common Share Data (3)					
Basic Earnings per Common Share	**$0.83**(1)	$1.63	$1.49	$0.30(2)	$1.51
Diluted Earnings per Common Share	**$0.82**(1)	$1.61	$1.47	$0.30(2)	$1.49
Dividends Declared	**$0.99**	$0.95	$0.92	$0.89	$0.86
Dividends Paid	**$0.97**	$0.94	$0.91	$0.88	$0.85
Dividend Rate at Year-End	**$1.01**	$0.96	$0.93	$0.90	$0.87
At September 30:					
Number of Common Shareholders	**20,345**	21,164	22,336	23,743	20,267
Net Property, Plant and Equipment *(Thousands)*					
Utility	**$945,693**	$939,753	$919,642	$906,754	$889,216
Pipeline and Storage	**483,222**	474,972	466,524	460,952	450,865
Exploration and Production	**1,081,622**	998,852	674,813	638,886	443,164
International	**178,250**	172,602	210,920	202,590	942
Energy Marketing	**262**	360	489	353	123
Timber	**90,453**	95,607	88,623	38,593	34,872
All Other	**1,209**	1,241	214	—	173
Corporate	**2**	4	7	9	11
Total Net Plant	**$2,780,713**	$2,683,391	$2,361,232	$2,248,137	$1,819,366
Total Assets *(Thousands)*	**$3,445,566**	$3,251,031	$2,842,586	$2,684,459	$2,267,331
Capitalization *(Thousands)*					
Comprehensive Shareholders' Equity	**$1,002,655**	$987,437	$939,293	$890,085	$913,704
Long-Term Debt, Net of Current Portion	**1,046,694**	953,622	822,743	693,021	581,640
Total Capitalization	**$2,049,349**	$1,941,059	$1,762,036	$1,583,106	$1,495,344

(1) 2001 includes oil and gas asset impairment of ($1.32) basic, ($1.29) diluted. Refer to further discussion of these items in Notes to Financial Statements, Note A - Summary of Significant Accounting Policies.
(2) 1998 includes oil and gas asset impairment of ($1.03) basic, ($1.02) diluted and cumulative effect of a change in depletion methods of ($0.12) basic and diluted.
(3) Per Common Share Data reflects two-for-one stock split on September 7, 2001.

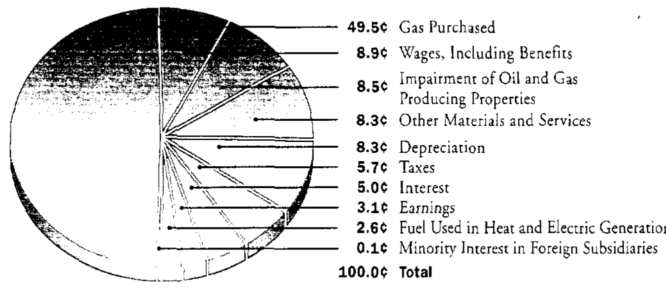
ITEM 7 Management's Discussion and Analysis of Financial Condition and Results of Operations

The Revenue Dollar - 2001

WHERE IT CAME FROM:



WHERE IT WENT TO:



Results of Operations

2001 Compared with 2000

The Company's earnings were $65.5 million, or $0.83 per common share ($0.82 per common share on a diluted basis) in 2001. These earnings included a non-cash impairment of oil and gas assets in the Exploration and Production segment in the amount of $104.0 million (after tax), or $1.32 per common share ($1.29 per common share on a diluted basis), which is discussed below. Without this non-cash asset impairment, earnings for 2001 would have been $169.5 million, or $2.14 per common share ($2.11 per common share on a diluted basis). This compares with 2000 earnings of $127.2 million, or $1.63 per common share ($1.61 per common share on a diluted basis). The increase in earnings of $42.3 million (exclusive of the non-cash impairment) was the result of higher earnings in the Exploration and Production, Utility, Pipeline and Storage, and Timber segments. Earnings were also positively impacted by a lower loss in the Energy Marketing segment. These higher earnings were offset by losses in 2001 in the International segment and Corporate operations compared to net income for this segment and these operations in 2000. Furthermore, the All Other category experienced an increased loss in 2001 compared to 2000. The higher loss in the All Other category resulted primarily from a natural gas inventory write-down by Upstate Energy Inc. (Upstate), the Company's wholly-owned subsidiary which is primarily engaged in wholesale natural gas marketing. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows.

Discussion of Asset Impairment

Seneca, which follows the full-cost method of accounting for its oil and gas operations, is required to perform a quarterly "ceiling test." Under the ceiling test, the present value of future revenues from Seneca's oil and gas reserves is compared (on a country by country basis) with the book value of those reserves at the balance sheet date. If the book value of the reserves in any country exceeds the present value of the associated future revenues, a non-cash charge must be recorded to write down the book value of the reserves to their present value. As a result of low oil and gas prices at September 30, 2001, Seneca was required to recognize a non-cash impairment relating to its Canadian properties of $180.8 million (pre tax) or $104.0 million (after tax) for the quarter ended September 30, 2001.

2000 Compared with 1999

The Company's earnings were $127.2 million, or $1.63 per common share ($1.61 per common share on a diluted basis) in 2000. This compares with 1999 earnings of $115.0 million, or $1.49 per common share ($1.47 per common share on a diluted basis). The increase in earnings of $12.2 million was the result of higher earnings in the Exploration and Production, Utility, Timber and International segments. These higher earnings were offset in part by lower earnings in the Pipeline and Storage segment, the Energy Marketing segment (which had a loss for the year) and in Corporate operations. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows.

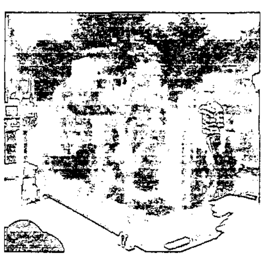
EARNINGS (LOSS) BY SEGMENT

Year Ended September 30 (Thousands)	2001	2000	1999
Utility	**$60,707**	$57,662	$56,875
Pipeline and Storage	**40,377**	31,614	39,765
Exploration and Production [1]	**(32,284)**	34,877	7,127
International	**(3,042)**	3,282	2,276
Energy Marketing	**(3,432)**	(7,790)	2,054
Timber	**7,715**	6,133	4,769
Total Reportable Segments	**70,041**	125,778	112,866
All Other	**(4,277)**	(371)	(162)
Corporate	**(265)**	1,800	2,333
Total Consolidated [1]	**$65,499**	$127,207	$115,037

(1) Exclusive of the non-cash asset impairment, 2001 earnings for the Exploration and Production segment and Total Consolidated would have been $71,756 and $169,539, respectively.

Utility

Revenues



UTILITY OPERATING REVENUES

Year Ended September 30 (Thousands)	2001	2000	1999
Retail Revenues:			
Residential	**$875,050**	$584,618	$581,022
Commercial	**154,266**	93,914	101,482
Industrial	**29,110**	21,543	15,903
	1,058,426	700,075	698,407
Off-System Sales	**84,078**	47,962	29,214
Transportation	**89,037**	104,534	77,600
Other	**3,106**	(6,112)	2,134
	$1,234,647	$846,459	$807,355

UTILITY THROUGHPUT – MILLION CUBIC FEET (MMCF)

Year Ended September 30	2001	2000	1999
Retail Sales:			
Residential	**73,530**	68,196	71,177
Commercial	**13,831**	12,312	13,885
Industrial	**4,089**	4,276	4,144
	91,450	84,784	89,206
Off-System Sales	**12,736**	12,833	12,469
Transportation	**66,283**	71,862	64,086
	170,469	169,479	165,761

2001 Compared with 2000

Operating revenues for the Utility segment increased $388.2 million in 2001 compared with 2000. This resulted from an increase in retail and off-system gas sales revenues of $358.4 million and $36.1 million, respectively. Other operating revenues also increased by $9.2 million. These increases were partly offset by a decrease in transportation revenues of $15.5 million.

The increase in retail gas revenues for the Utility segment was largely a function of the recovery of higher gas costs, coupled with an increase in retail sales volumes, as shown above. The recovery of higher gas costs (gas costs are recovered dollar for dollar in revenues) resulted from a much higher cost of purchased gas. See further discussion of purchased gas below under the heading "Purchased Gas." The increase in retail sales volumes was primarily the result of the migration of residential and small commercial customers from transportation service to retail service in both the New York and Pennsylvania jurisdictions, coupled with the impact of colder weather. This migration from transportation service resulted from one marketer entering bankruptcy proceedings, another marketer exiting the residential market, and the conclusion of a marketer pilot program in Pennsylvania. Off-system sales revenues increased because of higher gas prices. However, due to profit sharing with retail customers, the margins resulting from off-system sales were minimal. The decrease in transportation revenues and volumes was primarily due to residential transportation customers switching back to retail sales customers and the fact that certain commercial and industrial customers were reducing usage due to a slowing economy and/or were fuel switching.

The increase in other operating revenues was due primarily to $5.5 million of various revenue reductions in 2000 that did not recur in 2001 (of which $2.2 million was offset by lower operation and maintenance (O&M) expense in 2000). These revenue reductions related to the September 30, 2000 conclusion of the 1998 two-year rate settlement approved by the State of New York Public Service Commission (NYPSC). In addition to these adjustments, a $3.5 million lower provision for refund was recorded in 2001 as compared with 2000. The provision for refund in 2000 related to the conclusion of the 1998 two-year rate settlement and the provision for refund in 2001 relates to the current three-year rate settlement approved by the NYPSC in October 2000. The final refund for the current settlement will not be known until 2003.

Revenues in 2001 as compared to revenues in 2000 were reduced by a $10.0 million rate decrease for the Utility's New York customers that went into effect October 1, 2000 in connection with the current three-year rate settlement approved by the NYPSC. This rate decrease was provided in the form of a bill credit included in rates during the November 1, 2000 through March 31, 2001 heating season.

2000 Compared with 1999

Operating revenues for the Utility segment increased $39.1 million in 2000 compared with 1999. This resulted from an increase in retail, off-system, and transportation gas sales revenues of $1.7 million, $18.7 million, and $26.9 million, respectively. These increases were partly offset by a decrease in other operating revenues of $8.2 million.

The increase in retail gas revenues for the Utility segment was primarily due to the recovery of higher gas costs, offset by a decrease in the volumes sold. 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." The decrease in retail sales volumes was primarily the result of the migration of residential and small commercial customers to transportation service in both the New York and Pennsylvania jurisdictions, offset slightly by the impact of colder weather. Transportation revenues increased and volumes were up 7.8 billion cubic feet (Bcf) as a result of the migration noted above as well as the slightly colder weather. Off-system sales revenues increased largely due to increased gas prices and slightly higher volumes.

The decrease in other operating revenues of $8.2 million was largely due to $18.2 million of various revenue reductions ($9.7 million of which was offset by lower O&M expense) related to the September 30, 2000 conclusion of the 1998 two-year rate settlement approved by the NYPSC. Partly offsetting these decreases was the gas restructuring reserve which reduced revenues by $7.2 million in 1999. This special reserve, which did not recur in 2000, put aside dollars to be applied against incremental costs that could result from the NYPSC's gas restructuring efforts and was required in 1999 by the terms of the rate settlement with the NYPSC. The NYPSC's gas restructuring efforts are further discussed in the "Rate Matters" section that follows.

Earnings

2001 Compared with 2000

In the Utility segment, 2001 earnings were $60.7 million, up $3.0 million from the prior year. Items increasing earnings from the prior year include a $6.1 million (after tax) reduction in O&M expense representing the Utility segment's portion of the year-to-year change in the Company's stock appreciation right (SAR) expense, as discussed below, and the non-recurrence of $2.2 million (after tax) of revenue adjustments recorded in 2000 related to the conclusion of the 1998 two-year rate settlement, as discussed in the revenue section above. Colder weather in the Utility segment's Pennsylvania jurisdiction also increased earnings by $3.1 million (after tax), as discussed below. Furthermore, the lower provision for refund in 2001 as compared to 2000, as discussed in the revenue section above, had a positive contribution to earnings of $2.3 million (after tax). These items were offset by a $10.0 million rate decrease ($6.5 million after tax) in the Utility segment's New York jurisdiction, as previously discussed. Also, the Utility segment recorded an early retirement expense in its Pennsylvania jurisdiction ($0.6 million after tax) during the first quarter of 2001 and an early retirement expense in its New York jurisdiction ($3.6 million after tax) during the second quarter of 2001.

The decrease in the market price of the Company's common stock during 2001 carried with it a reduction in the Company's SAR liability. This reduction is spread across all segments, with the greatest impact on the Pipeline and Storage, Utility and Exploration and Production segments. For 2001, the Company experienced a reduction in its SAR liability (reflected through lower total Company O&M expense of $8.9 million after tax) as the market price of the Company's common stock decreased from September 30, 2000 ($28.03 per common share) to September 30, 2001 ($23.03 per common share). For 2000, the Company experienced an increase in its SAR liability (reflected through higher total Company O&M expense of $9.2 million after tax) as the market price of the Company's common stock increased from September 30, 1999 ($23.59 per common share) to September 30, 2000 ($28.03 per common share).

The impact of weather on the Utility segment's New York rate jurisdiction is tempered by a weather normalization clause (WNC). The WNC in New York, 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 2001, the WNC in New York preserved earnings of approximately $1.2 million (after tax) as weather, overall in the New York service territory, was warmer than normal for the period from October 2000 through May 2001. Since the Pennsylvania jurisdiction does not have a WNC, uncontrollable weather variations directly impact earnings. In the Pennsylvania service territory, weather during 2001 was 12.3% colder than 2000 and 2.8% colder than normal.

2000 Compared with 1999

In the Utility segment, 2000 earnings were $57.7 million, up $0.8 million from 1999. The increase in earnings resulted primarily from two items in 1999 (expenses related to an early retirement offer of $3.7 million (after tax) and a special reserve for gas restructuring of $4.7 million (after tax) which did not recur in 2000). These items were offset by an increase in the Utility segment's portion of the Company's SAR expense, reflected through higher O&M expense of $2.9 million (after tax), as discussed above, and revenue adjustments of $5.5 million (after tax), as discussed in the revenue section above.

In 2000, the WNC in New York preserved earnings of approximately $8.1 million (after tax) as weather, overall in the New York service territory, was warmer than normal for the period from October

1999 through May 2000. Since the Pennsylvania rate jurisdiction does not have a WNC, uncontrollable weather variations directly impact earnings. In the Pennsylvania service territory, since weather in 2000 was only 0.9% colder than 1999, no significant earnings variances occurred.

DEGREE DAYS

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Percent (Warmer) Colder Than Prior Year
2001:	**Buffalo**	**6,865**	**6,648**	**(3.2%)**	**5.3%**
	Erie	**6,179**	**6,351**	**2.8%**	**12.3%**
2000:	Buffalo	6,932	6,312	(8.9%)	2.1%
	Erie	6,230	5,657	(9.2%)	0.9%
1999:	Buffalo	6,848	6,179	(9.8%)	4.5%
	Erie	6,223	5,607	(9.9%)	4.0%

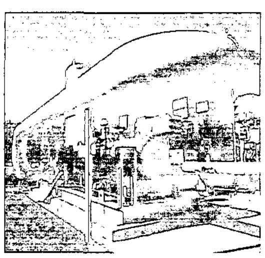
Purchased Gas

The cost of purchased gas is currently the Company's single largest operating expense. Annual variations in purchased gas costs can be 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 can satisfy a portion of its gas requirements through spot market purchases. Changes in wellhead prices have a direct impact on the cost of purchased gas. Distribution Corporation's average cost of purchased gas, including the cost of transportation and storage, was $7.35 per thousand cubic feet (Mcf) in 2001, an increase of 49% from the average cost of $4.93 per Mcf in 2000. The average cost of purchased gas in 2000 was 29% higher than the $3.82 per Mcf in 1999.

Pipeline and Storage

Revenues



PIPELINE AND STORAGE OPERATING REVENUES

Year Ended September 30 (Thousands)	2001	2000	1999
Firm Transportation	**$91,611**	$92,305	$91,279
Interruptible Transportation	**1,917**	1,578	856
	93,528	93,883	92,135
Firm Storage Service	**61,559**	62,899	63,655
Interruptible Storage Service	**670**	287	173
	62,229	63,186	63,828
Other	**15,334**	12,590	12,820
	$171,091	$169,659	$168,783

PIPELINE AND STORAGE THROUGHPUT – (MMCF)

Year Ended September 30	2001	2000	1999
Firm Transportation	**304,183**	291,818	300,242
Interruptible Transportation	**17,372**	21,730	8,061
	321,555	313,548	308,303

2001 Compared with 2000

Operating revenues for the Pipeline and Storage segment increased $1.4 million in 2001 compared with 2000. The increase is attributable primarily to a $2.1 million increase in revenues from unbundled pipeline sales and open access transportation due to higher prices and volumes. While transportation volumes increased 8.0 Bcf during the fiscal year, volume fluctuations generally do not have a significant impact on revenues as a result of Supply Corporation's straight fixed-variable (SFV) rate design.

2000 Compared with 1999

Operating revenues increased $0.9 million in 2000 compared with 1999. The increase resulted primarily from higher firm transportation revenue of $1.0 million and higher interruptible transportation and interruptible storage service revenues of $0.8 million, offset by lower firm storage service revenue of $0.8 million. The increase in firm transportation revenues resulted primarily from a $1.3 million "pass-through" type item (which did not recur in 2000) that reduced revenues in the prior year and correspondingly reduced O&M expense in the prior year, thus having no earnings impact. The increase in interruptible transportation and interruptible storage service revenues is principally the result of higher throughput volumes. The decrease in firm storage service revenue was the result of discounted storage service rates, as well as the loss of certain storage service customers. Transportation volumes in this segment increased 5.2 Bcf. Generally, volume fluctuations do not have a significant impact on revenues as a result of Supply Corporation's SFV rate design.

Earnings

2001 Compared with 2000

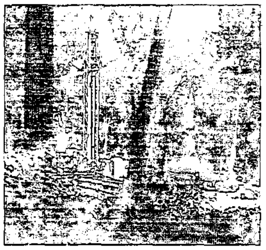
The Pipeline and Storage segment's earnings for 2001 were $40.4 million, an increase of $8.8 million when compared with earnings for 2000. This increase in earnings is attributable to an $8.8 million (after tax) reduction in O&M expenses associated with the Pipeline and Storage segment's portion of the year-to-year change in the Company's SAR expense, as previously discussed. Also, there was a $1.3 million (after tax) increase in revenues from unbundled pipeline sales and open access transportation. The increase in earnings is also attributable to the buy-out by a customer of a long-term transportation contract ($2.6 million after tax) during the first quarter of 2001. The resulting gain from this buy-out was recorded in other income. As a partial offset to these earnings increases, this segment recorded early retirement expenses of $1.2 million (after tax) in the first and second quarters of 2001. This segment also recorded additional executive retirement benefit expenses of $2.1 million (after tax) in 2001.

2000 Compared with 1999

Earnings in the Pipeline and Storage segment decreased $8.2 million in 2000 compared with 1999. In 2000, increased O&M expenses of $4.6 million (after tax) associated with the Pipeline and Storage segment's portion of the year-to-year change in the Company's SAR expense, as previously discussed, and the addition of $1.1 million of New York State income tax, resulting from a change in the tax laws in New York State, contributed to the decrease in earnings. The Federal Energy Regulatory Commission (FERC), which regulates this segment, has not provided for the recovery of additional taxes as has the New York Department of Public Service. Several items in 1999, which did not recur in 2000, also contributed to 2000 earnings being less than 1999 earnings. The 1999 earnings included interest income of $1.2 million (after tax) and a reduction in income tax of $1.7 million related to the final settlement of IRS audits of years 1977-1994. In addition, 1999 included the recovery of $0.5 million (after tax) of costs related to a gathering project that had been previously reserved for and the recovery, through insurance, of $0.4 million (after tax) of a previously expensed base gas loss. These items were offset in part by a charge in 1999 for an early retirement of $0.9 million (after tax).

Exploration and Production

Revenues



EXPLORATION AND PRODUCTION OPERATING REVENUES

Year Ended September 30 (Thousands)	2001	2000	1999
Gas (after Hedging)	**$171,045**	$108,832	$83,229
Oil (after Hedging)	**169,613**	117,606	52,050
Gas Processing Plant	**39,986**	17,666	11,751
Other	**17,700**	(6,034)	(36)
	$398,344	$238,070	$146,994

PRODUCTION VOLUMES

Year Ended September 30	2001	2000	1999
Gas Production *(MMcf)*			
Gulf Coast	**30,663**	32,760	28,758
West Coast	**4,383**	4,374	3,977
Appalachia	**4,142**	4,344	4,431
Canada	**1,816**	192	—
	41,004	41,670	37,166
Oil Production *(thousands of barrels) (Mbbl)*			
Gulf Coast	**1,914**	1,415	1,373
West Coast	**2,875**	2,824	2,633
Appalachia	**7**	9	10
Canada	**3,061**	899	—
	7,857	5,147	4,016

AVERAGE PRICES

Year Ended September 30	2001	2000	1999
Average Gas Price/Mcf			
Gulf Coast	**$4.93**	$3.29	$2.15
West Coast	**$10.18**	$3.62	$2.28
Appalachia	**$5.03**	$3.16	$2.44
Canada	**$2.41**	$2.52	—
Weighted Average	**$5.39**	$3.31	$2.20
Weighted Average After Hedging (1)	**$4.17**	$2.61	$2.24
Average Oil Price/barrel (bbl)			
Gulf Coast	**$27.47**	$28.27	$15.18
West Coast (2)	**$24.06**	$23.87	$11.62
Appalachia	**$28.51**	$25.12	$14.73
Canada	**$24.29**	$29.28	—
Weighted Average	**$24.99**	$26.03	$12.85
Weighted Average After Hedging (1)	**$21.59**	$22.85	$12.96

(1) Refer to further discussion of hedging activities below under "Market Risk Sensitive Instruments" and in Note F – Financial Instruments in Item 8 of this report.
(2) Includes low gravity oil which generally sells for a lower price.

2001 Compared with 2000

Operating revenues for the Exploration and Production segment increased $160.3 million in 2001 compared with 2000. Gas production revenue after hedging increased $62.2 million due primarily to an increase in the weighted average price of gas after hedging. Overall gas production decreased, primarily in the Gulf Coast region, as there were delays in placing new platforms on production (due to rig availability constraints) and delays in work-over activity, mostly during the first and second quarters of 2001. New Gulf Coast production in the second half of 2001 was primarily oil production. Gas production from the Canadian properties acquired in June 2001 (i.e., the Player Petroleum Corp. acquisition) (Player) helped mitigate the gas production decline in the Gulf Coast region. Oil production revenue after hedging increased $52.0 million in 2001 compared with 2000. This increase is due primarily to a 53% increase in oil production, largely attributable to the Exploration and Production segment's Canadian properties acquired in June 2000. Revenue from this segment's gas processing plant was up $22.3 million due to higher prices. In addition, this segment recognized other revenue increases of $23.8 million due to mark-to-market and other revenue adjustments related to derivative financial instruments. Refer to further discussion of derivative financial instruments under the heading "Market Risk Sensitive Instruments" that follows.

2000 Compared with 1999

Operating revenues increased $91.1 million in 2000 compared with 1999. Oil production revenues after hedging increased $65.6 million as the weighted average price of oil after hedging increased 76% and oil production increased 28% from 1999 compared to 2000. Oil production from Canadian wells acquired as part of the June 2000 acquisition of Tri Link Resources, Ltd. (Tri Link) added $26.3 million to oil revenues. Gas production revenues after hedging increased $25.6 million as gas production increased 12% and the weighted average price of gas after hedging increased 17%. Revenue from Seneca's gas processing plant was up $5.9 million. These items were partly offset by a $6.0 million decrease in other revenues resulting primarily from mark-to-market and other revenue adjustments related to written options.

Earnings

2001 Compared with 2000

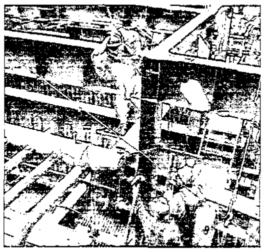
The Exploration and Production segment experienced a loss of $32.3 million in 2001, a decrease of $67.2 million when compared to 2000 earnings of $34.9 million. Excluding the $104.0 million after tax non-cash impairment of this segment's Canadian oil and gas assets, as previously discussed, this segment had 2001 earnings of $71.8 million, an increase of $36.9 million from 2000 earnings. A 53% increase in oil production, largely attributable to the Canadian properties acquired in June 2000, combined with higher natural gas prices, were major factors in this segment's earnings increase, exclusive of the non-cash asset impairment. Also, this segment's earnings benefited from the mark-to-market revenue increases discussed above. Partly offsetting higher revenues was an increase in production related expenses, including higher depletion, higher purchased gas expense (for the gas processing plant), an increase in lease operating costs and higher production taxes. General and administrative expenses (G&A) increased in total, largely due to the Player and Tri Link acquisitions, offset by the impact of the Exploration and Production segment's portion of the year-to-year change in the Company's SAR expense, as previously discussed. Greater interest expense due to higher borrowings related to the Player and Tri Link acquisitions also partially offset the positive impact of higher revenues.

2000 Compared with 1999

In the Exploration and Production segment, 2000 earnings of $34.9 million were up $27.8 million when compared with 1999. The Canadian properties acquired in June 2000 added $6.4 million to 2000 earnings. As discussed above, significant improvement in oil and gas pricing, combined with an increase in production, were the main reasons for higher earnings. Partly offsetting higher revenues was an increase in production-related expenses, including higher depletion, an increase in lease operating costs, and higher production taxes. In addition, G&A was up as a result of higher costs associated with labor and benefits (including SAR expense), and interest expense increased due to higher borrowings related to the acquisition of Tri Link. The increase in the gas processing plant revenue of $5.9 million was offset by an equal amount of related expense.

International

Revenues



INTERNATIONAL OPERATING REVENUES

Year Ended September 30 (Thousands)	2001	2000	1999
Heating	**$69,072**	$69,387	$71,974
Electricity	**26,398**	31,426	34,158
Other	**2,440**	3,923	913
	$97,910	$104,736	$107,045

INTERNATIONAL HEATING AND ELECTRIC VOLUMES

Year Ended September 30	2001	2000	1999
Heating Sales (Gigajoules)[1]	**9,978,118**	10,222,024	10,047,042
Electricity Sales (megawatt hours)	**1,019,901**	1,147,303	1,138,980

(1) Gigajoules = one billion joules. A joule is a unit of energy.

2001 Compared with 2000

Operating revenues decreased $6.8 million in 2001 compared with 2000. The revenue decrease largely reflects a decrease in the average value of the Czech koruna (CZK) compared to the U.S. dollar during the 2001 heating season compared to the 2000 heating season. Exclusive of the exchange rate impact, heating revenues are actually up due to rate increases offset partly by lower volumes associated with warmer weather. Electric revenues, exclusive of the exchange rate impact, decreased as a result of lower volumes (principally attributable to the scheduled shutdown of a generating turbine that had reached the end of its useful life) and a decline in electric rates.

2000 Compared with 1999

Operating revenues decreased $2.3 million in 2000 compared with 1999. The decrease in revenues is largely due to the decrease in value of the CZK as compared to the U.S. dollar. While higher heating and electricity sales contributed to higher operating revenues (in CZK), the decrease in value of the CZK caused an overall decrease in revenues when translated into U.S. dollars.

Earnings

2001 Compared with 2000

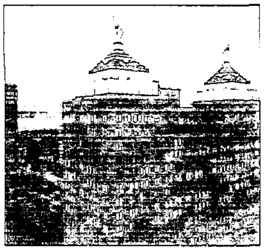
The International segment experienced a loss of $3.0 million in 2001 compared with 2000 earnings of $3.3 million. Lower heat and electric margins, as a result of warmer weather and the scheduled shutdown of a generating turbine, are the primary reasons for this decrease. The decrease also reflects a decrease in value of the CZK compared to the U.S. dollar, as previously discussed.

2000 Compared with 1999

The International segment's 2000 earnings were $3.3 million, or $1.0 million higher than 1999 earnings. This increase can be attributed to lower O&M expense, an income tax adjustment that benefited earnings in 2000, and additional consideration received in 2000 on the sale of a previously written-off project. These were partly offset by a decrease in margin and the negative impact of the decline in the exchange rate, as discussed above.

Energy Marketing

Revenues



ENERGY MARKETING OPERATING REVENUES

Year Ended September 30 (Thousands)	2001	2000	1999
Natural Gas (after Hedging)	$257,005	$139,614	$97,514
Electricity	1,362	1,941	1,551
Other	839	(7,626)	23
	$259,206	$133,929	$99,088

ENERGY MARKETING VOLUMES

Year Ended September 30	2001	2000	1999
Natural Gas – (MMcf)	37,427	35,465	34,454

2001 Compared with 2000

Operating revenues increased $125.3 million in 2001 compared with 2000. The primary reason for this increase was the higher gas costs that are reflected in the natural gas marketing revenues. Higher marketing volumes are primarily due to colder weather in 2001 compared to 2000. This compensated for a 4% decrease in NFR customers from September 30, 2000 to September 30, 2001. In addition, NFR recognized a negative $8.6 million mark-to-market adjustment related to certain derivative financial instruments (included in "Other" on the table above) during 2000. NFR experienced positive mark-to-market adjustments in 2001 of $0.5 million. See further discussion of NFR's use of derivatives in the "Market Risk Sensitive Instruments" section that follows and in Note F – Financial Instruments in Item 8 of this report.

2000 Compared with 1999

Operating revenues increased $34.8 million in 2000 compared with 1999. The primary reason for this increase was higher gas costs that are reflected in the natural gas marketing revenues. In addition, higher marketing volumes reflect an increase in NFR customers from 17,480 at September 30, 1999 to 33,115 at September 30, 2000. Almost 89% of the increase in customers were residential customers. These higher revenues were offset in part by a negative $8.6 million mark-to-market adjustment discussed above.

Earnings

2001 Compared with 2000

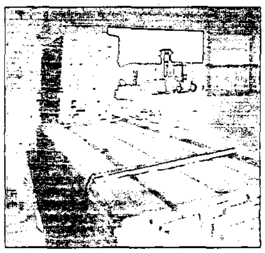
The Energy Marketing segment incurred a loss for 2001 of $3.4 million, a decrease of approximately $4.4 million compared with the loss of $7.8 million in 2000. The most significant reason for the lower loss was the change in mark-to-market adjustments from 2000 to 2001 ($5.9 million positive contribution after tax), referred to above. Lower margins, higher O&M expense, mainly attributable to higher bad debt expense, and higher interest expense in 2001 compared to 2000 partially offset the effect of these adjustments.

2000 Compared with 1999

The Energy Marketing segment incurred a loss for 2000 of $7.8 million, a decrease of approximately $9.9 million over 1999 earnings of $2.1 million. The most significant reasons for the decrease were mark-to-market losses related to certain derivative financial instruments of $5.6 million (after tax), the accrual of a $1.6 million (after tax) loss contingency on the unhedged portion of this segment's fixed price sales contracts for sale of natural gas to customers in 2001, and higher expenses including interest.

Timber

Revenues



TIMBER OPERATING REVENUES

Year Ended September 30 (Thousands)	2001	2000	1999
Log Sales	**$23,460**	$24,091	$18,276
Green Lumber Sales	**5,597**	4,397	4,018
Kiln Dry Lumber Sales	**12,320**	10,152	8,197
Other	**714**	532	626
	$42,091	$39,172	$31,117

TIMBER BOARD FEET

Year Ended September 30 (Thousands)	2001	2000	1999
Log Sales	**8,839**	9,370	6,902
Green Lumber Sales	**10,332**	8,193	8,541
Kiln Dry Lumber Sales	**8,804**	6,987	5,711
	27,975	24,550	21,154

2001 Compared with 2000

Operating revenues for the Timber segment increased $2.9 million. Green lumber sales were up due to an increase in board feet sold at slightly higher prices. The increase in kiln dry lumber sales is due to the operation of two additional kilns brought on line in August 2000. The decrease in log sales revenues primarily reflects lower sales of quality logs offset partly by higher average prices.

2000 Compared with 1999

Operating revenues for the Timber segment increased $8.1 million. This increase was primarily the result of higher log sales and kiln dry lumber sales. Log sales were up due mainly to higher board feet of cherry veneer and export logs sold and higher average prices. The increase in kiln dry lumber sales is due to the operation of additional kilns brought on line in 1999 that were operational for a full 12 months in 2000 and the addition of two more kilns brought on line in August 2000.

Earnings

2001 Compared with 2000

Timber segment earnings of $7.7 million in 2001 were up $1.6 million compared with 2000. The increase is primarily due to higher operating revenues, as mentioned above, and lower interest expense.

2000 Compared with 1999

Timber segment earnings of $6.1 million in 2000 were up $1.4 million compared with 1999. The increase was due to higher operating revenues, as mentioned above, and an after tax gain on the sale of land and standing timber of $1.5 million. These items were partly offset by higher interest expense resulting from higher debt related to an acquisition in July 1999 and by higher operating expenses.

Other Income and Interest Charges

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

Other Income

Other income increased $4.8 million in 2001 compared with 2000. This increase resulted primarily from a $4.0 million buyout of a long-term transportation contract by a customer in the Pipeline and Storage segment during the first quarter of 2001.

Other income decreased $1.9 million in 2000 compared with 1999. This decrease resulted from $3.2 million of interest income related to the final settlement of IRS audits of years 1977-1994 which was recorded during 1999, as well as a $2.4 million gain recorded in 1999 which resulted from the demutualization of an insurance company. As a policyholder, the Company received stock of the insurance company as part of its initial public offering. Neither of these items recurred in 2000. Partly offsetting this decrease was a $2.6 million gain on the sale of land and standing timber in 2000, as well as $0.5 million of additional consideration received in 2000 on the sale of a previously written-off project in the International segment.

Interest Charges

Interest on long-term debt increased $14.7 million in 2001 and $1.8 million in 2000. The increase in both years can be attributed mainly to a higher average amount of long-term debt outstanding. Long-term debt balances have grown significantly over the past few years primarily as a result of acquisition activity in the Exploration and Production segment.

Other interest charges decreased $7.6 million in 2001 and increased $10.6 million in 2000. The decrease in 2001 was primarily the result of lower weighted average interest rates on short-term debt. The increase in 2000 resulted primarily from higher weighted average interest rates and higher average amounts 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 (Millions)	**2001**	**2000**	**1999**
Provided by Operating Activities	**$414.1**	$238.2	$267.5
Capital Expenditures	**(292.7)**	(269.4)	(256.1)
Investment in Subsidiaries, Net of Cash Acquired	**(90.6)**	(123.8)	(5.8)
Investment in Partnerships	**(1.8)**	(4.4)	(3.6)
Other Investing Activities	**(2.9)**	13.3	6.7
Short-Term Debt, Net Change	**(143.4)**	226.5	67.2
Long-Term Debt, Net Change	**187.2**	(18.1)	(15.6)
Issuance of Common Stock	**11.5**	14.3	10.7
Dividends Paid on Common Stock	**(76.7)**	(73.0)	(69.9)
Dividends Paid to Minority Interest	**—**	(0.2)	(0.2)
Effect of Exchange Rates on Cash	**(0.6)**	(0.5)	(2.1)
Net Increase (Decrease) in Cash and Temporary Cash Investments	**$4.1**	$2.9	$(1.2)

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, deferred income taxes, minority interest in foreign subsidiaries and the impairment of oil and gas producing properties (2001).

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 SFV rate design.

Net cash provided by operating activities totaled $414.1 million in 2001, an increase of $175.9 million compared with the $238.2 million provided by operating activities in 2000. The increase is attributable primarily to higher cash receipts from the sale of oil and gas in the Exploration and Production segment. Gas prices were up significantly for most of 2001 and oil production increased significantly due to this segment's Canadian properties acquired in June 2000, offsetting a slight overall decrease in oil prices. The increase in cash provided by operating activities also reflects the over-recovery of purchased gas costs in the Utility segment during 2001.

Investing Cash Flow

Expenditures for Long-Lived Assets

Expenditures for long-lived assets include additions to property, plant and equipment (capital expenditures) and investments in corporations (stock acquisitions) or partnerships, net of any cash acquired.

The Company's expenditures for long-lived assets totaled $385.1 million in 2001. The table below presents these expenditures:

Year Ended September 30, 2001 (Millions)	Capital Expenditures	Investments In Corporations or Partnerships	Total Expenditures For Long-Lived Assets
Utility	$42.4	$ —	$42.4
Pipeline and Storage	25.0	1.0	26.0
Exploration and Production	205.8	90.6	296.4
International	15.6	—	15.6
Energy Marketing	0.1	—	0.1
Timber	3.7	—	3.7
All Other	0.1	0.8	0.9
	$292.7	$92.4	$385.1

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 Pipeline and Storage segment's capital expenditures made during 2001 included $8.1 million for the construction of a transmission line from Lamont, Pennsylvania to Roystone, Pennsylvania. The remaining capital expenditures were made for additions, improvements and replacements to this segment's transmission and gas storage systems.

During 2001, SIP made an additional $980,000 investment in Independence. SIP's total investment through September 30, 2001 was $14.6 million. The investment represents a one-third partnership interest in Independence. The investment has been financed with short-term borrowings. Independence intends to build the Independence Pipeline, a 400-mile natural gas pipeline from Defiance, Ohio to Leidy, Pennsylvania at an estimated cost of about $700 million.* If the Independence Pipeline project is not constructed, SIP's share of the developmental costs (including SIP's investment in Independence) is estimated not to exceed $15.5 million.* This amount represents the estimated maximum charge to earnings that would be recorded if the project is not constructed.

On July 12, 2000, the Federal Energy Regulatory Commission (FERC) issued a Certificate of Public Convenience and Necessity (the Certificate) authorizing, among other things, the construction and operation of the Independence Pipeline, subject to satisfaction of various conditions spelled out in the Certificate and in previous FERC orders. Independence accepted the Certificate on August 14, 2000. Among the conditions to the construction and operation of the pipeline is the requirement that the pipeline be in service by July 12, 2003. Another condition is that, before construction may commence, Independence must file at FERC executed, firm transportation agreements with "no out" clauses for at least 68.2% of its capacity. (Independence already filed, on June 26 and July 6, 2000, precedent agreements for firm transportation amounting to about 38% of the capacity of the Independence Pipeline, thereby satisfying a FERC requirement previously imposed as a precondition to FERC's issuance of the Certificate.) The Independence Pipeline partners are working on obtaining the required additional customer commitments, and had extended the planned in-service date from November 1, 2002 to July 1, 2003 to allow additional time to obtain those commitments.

The Certificate also includes an environmental condition that Independence file an "implementation plan" within 60 days after Independence accepts the Certificate. FERC extended the due date for submission of that implementation plan to November 1, 2001. On November 1, 2001, Independence filed a partial implementation plan with FERC seeking to extend the due date for a complete implementation plan to November 2003 and to extend the in service date to November 2004. As of the date the Company filed this Form 10-K with the SEC, FERC had placed the Independence Pipeline project on the agenda for its December 19, 2001 meeting but had not decided upon Independence's requests for extensions. If FERC does not grant these extensions, it may revoke the Certificate. If the Certificate is revoked and the Independence partners decide to proceed with the project, they would file a new application at FERC after obtaining additional customer commitments.

The Company also continues to explore various opportunities to participate in transporting gas to the Northeast, either through Supply's system or in partnership with others. This includes the proposed Northwinds Pipeline that the Company and TransCanada PipeLines Limited are pursuing. This project would be a 215-mile, 30-inch natural gas pipeline that would originate in Kirkwall, Ontario, cross into the United States near Buffalo, New York and follow a southerly route to its destination in the Ellisburg-Leidy area in Pennsylvania. The initial capacity of the pipeline would be approximately 500 million cubic feet of natural gas per day with the estimated cost of the pipeline ranging from $350 - $400 million. At September 30, 2001, the Company had not incurred any material costs associated with this project. The Company would be interested in building the Independence Pipeline and/or the Northwinds Pipeline if there are sufficient customer commitments.

Exploration and Production

The Exploration and Production segment's capital expenditures included approximately $116.6 million of capital expenditures for on-shore drilling, construction and recompletion costs for wells located in Louisiana, Texas, California and Canada as well as on-shore geological and geophysical costs, including the purchase of certain three-dimensional seismic data and fixed asset purchases. Of the $116.6 million discussed above, $56.8 million was spent on the Exploration and Production segment's Canadian properties. The Exploration and Production segment's capital expenditures also included approximately $89.2 million for Seneca's offshore program in the Gulf of Mexico, including offshore drilling expenditures, offshore construction, lease acquisition costs and geological and geophysical expenditures.

In June 2001, the Company acquired the issued and outstanding shares of Player, an oil and gas exploration and development company with operations based primarily in the Province of Alberta, Canada. The cost of acquiring the shares of Player was approximately $90.6 million. The acquisition was financed with short-term borrowings.

International

The majority of the International segment's capital expenditures were concentrated on the construction of boilers at a district heating and power generation plant in the Czech Republic. In June 2001, the Company sold its ownership interest in Jablonecká teplárenská a realitní, a.s. (JTR). JTR is a district heating plant in the northern part of the Czech Republic. The proceeds from this sale, net of cash sold, were $5.6 million. There was a loss of less than $0.1 million on the sale.

Timber

The majority of the Timber segment's capital expenditures were made for purchases of land and timber, as well as equipment for this segment's sawmill and kiln operations. In November 2000, this segment sold timber properties with a book value of $5.2 million for $7.3 million. In April 2001, this segment sold land having a minimal book value for $0.6 million.

All Other

Expenditures for Long-Lived Assets for all other subsidiaries consisted of the purchase of a 50% partnership interest in Model City Energy, LLC (Model City) ($0.3 million) and the purchase of a 50% partnership interest in Energy Systems North East, LLC (ESNE) ($0.5 million). The Company also financed ESNE with a long-term note in the principal amount of $11.5 million. Model City generates electricity by using methane gas obtained from a landfill in Model City, New York, which is owned by an outside party. ESNE is an 80-megawatt power plant located in North East, Pennsylvania. The plant provides thermal energy to an adjacent, industrial facility, as well as electric power to the New York power pool.

Estimated Capital Expenditures

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

Year Ended September 30 (Millions)	2002	2003	2004
Utility	$49.6	$49.6	$50.1
Pipeline and Storage	30.8	26.2	27.5
Exploration and Production	141.0	117.2	108.8
International	5.5	1.7	1.7
Timber	1.5	1.5	1.5
	$228.4	$196.2	$189.6

Estimated capital expenditures for the Utility segment in 2002 will be concentrated in the areas of main and service line improvements and replacements and, to a minor extent, the installation of new services.*

Estimated capital expenditures for the Pipeline and Storage segment in 2002 will be concentrated in the reconditioning of storage wells and the replacement of storage and transmission lines.* The estimated capital expenditures also include $6.3 million for an increase in horsepower at the Ellisburg, Pennsylvania compressor station.* The estimated capital expenditures do not include any partnership investments for Independence or the Northwinds Pipeline.

Estimated capital expenditures in 2002 for the Exploration and Production segment include approximately $88.0 million for the onshore program ($47.0 million in Canada).* Of this amount, approximately $59.0 million ($26.0 million in Canada) is intended to be spent on exploratory and development drilling.*

The estimated expenditures also include approximately $53.0 million for the offshore program in the Gulf of Mexico.* Of this amount, approximately $27.0 million is intended to be spent on exploratory and development drilling.*

The estimated capital expenditures for the International segment in 2002 will be concentrated on improvements and replacements within the district heating and power generation plants in the Czech Republic.*

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

The Company continuously evaluates capital expenditures and investments in corporations and partnerships. The amounts are subject to modification for opportunities such as the acquisition of attractive oil and gas properties, timber or storage facilities and the expansion of 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

In November 2000, the Company issued $200.0 million of 7.50% medium-term notes due in November 2010. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $197.3 million. The proceeds of this debt issuance were used to reduce short-term debt.

Consolidated short-term debt decreased $143.4 million during 2001. The Company continues to consider short-term debt 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, 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's present liquidity position is believed to be adequate to satisfy known demands.* Under the Company's existing indenture covenants, at September 30, 2001, the Company would have been permitted to issue up to a maximum of $322.0 million in additional long-term unsecured indebtedness at projected market interest rates. Excluding the unrealized gain for derivative financial instruments reflected in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheet, the Company would have been permitted to issue up to a maximum of $296.0 million in additional long-term unsecured indebtedness at projected market interest rates. In addition, at September 30, 2001, the Company had regulatory authorizations and unused short-term credit lines that would have permitted it to borrow an additional $260.3 million of short-term debt.

The Company's embedded cost of long-term debt was 7.0% at both September 30, 2001 and 2000, respectively.

In November 2001, the Company issued $150.0 million of 6.70% medium-term notes due in November 2011. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $149.0 million. The proceeds of this debt issuance were used to reduce short-term debt.

In March 1998, the Company obtained authorization from the Securities and Exchange Commission (SEC), under the Public Utility Holding Company Act of 1935, to issue long-term debt securities and equity securities in amounts not exceeding $2.0 billion at any one time outstanding during the order's authorization period, which extends to December 31, 2002. In August 1999, the Company registered $625.0 million of debt and equity securities under the Securities Act of 1933. After the November 2001 medium-term note issuance discussed above, the Company currently has $125.0 million of securities registered under the Securities Act of 1933.

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

The Company is involved in litigation arising in the normal course of business. The Company is involved in regulatory matters arising in the normal course of business that involve 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 year of resolution, none of this litigation, and none of these regulatory matters are currently expected to change materially the Company's present liquidity position, nor have a material adverse effect on the financial condition of the Company.*

Market Risk Sensitive Instruments

Energy Commodity Price Risk

The Company, primarily in its Exploration and Production and Energy Marketing segments, 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, 2001 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 New York Mercantile Exchange. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the prices as of September 30, 2001. At September 30, 2001, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2003.

NATURAL GAS PRICE SWAP AGREEMENTS

	Expected Maturity Dates		
	2002	**2003**	**Total**
Notional Quantities (Equivalent Bcf)	26.4	1.1	27.5
Weighted Average Fixed Rate (per Mcf)	$3.82	$2.80	$3.77
Weighted Average Variable Rate (per Mcf)	$2.40	$2.35	$2.39

CRUDE OIL PRICE SWAP AGREEMENTS

	Expected Maturity Dates		
	2002	**2003**	**Total**
Notional Quantities (Equivalent bbls)	4,840,980	1,803,000	6,643,980
Weighted Average Fixed Rate (per bbl)	$22.98	$19.93	$22.15
Weighted Average Variable Rate (per bbl)	$26.49	$26.50	$26.49

At September 30, 2001, the Company would have received from the respective counterparties an aggregate of approximately $25.7 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have had to pay an aggregate of approximately $7.5 million to the counterparties to terminate the crude oil price swap agreements outstanding at September 30, 2001.

At September 30, 2000, the Company had natural gas price swap agreements covering 44.9 Bcf at a weighted average fixed rate of $3.34 per Mcf. The Company also had crude oil price swap agreements covering 10,361,895 bbls at a weighted average fixed rate of $21.75 per bbl. As indicated in the tables above, the Company has significantly reduced its use of natural gas and crude oil price swap agreements, which is primarily attributable to the pricing environment during the latter part of 2000 compared to 2001. In the latter part of 2000, prices were on the rise, allowing the Company to lock in favorable prices. In the latter part of 2001, prices were falling providing less opportunities for the Company to lock in favorable prices. Furthermore, the Company has changed its hedging strategy by using more natural gas no cost collars and options (puts) to allow the Company to share in more of the upside potential of commodity prices while limiting the downside risk.

The following tables disclose 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 and crude oil 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, 2001, the Company had not entered into any natural gas or crude oil no cost collars extending beyond 2004.

NO COST COLLARS

	Expected Maturity Dates			
	2002	2003	2004	Total
Crude Oil				
Notional Quantities (Equivalent bbls)	1,335,000	1,125,000	270,000	2,730,000
Weighted Average Ceiling Price (per bbl)	$28.26	$26.41	$25.80	$27.25
Weighted Average Floor Price (per bbl)	$21.91	$21.96	$22.00	$21.94
Natural Gas				
Notional Quantities (Equivalent Bcf)	2.8	6.2	0.2	9.2
Weighted Average Ceiling Price (per Mcf)	$5.61	$5.28	$4.40	$5.36
Weighted Average Floor Price (per Mcf)	$4.11	$4.05	$3.71	$4.06

At September 30, 2001, the Company would have received from the respective counterparties an aggregate of approximately $11.2 million to terminate the natural gas no cost collars outstanding at that date. The Company would have received an aggregate of approximately $2.3 million to terminate the crude oil no cost collars outstanding at that date.

At September 30, 2000, the Company had crude oil no cost collars covering 4,725,000 bbls at a weighted average floor price of $22.49 per bbl and a weighted average ceiling price of $28.44 per bbl. The Company also had natural gas no cost collars covering 6.6 Bcf at a weighted average floor price of $3.83 per Mcf and a weighted average ceiling price of $5.75 per Mcf.

The following table discloses the notional quantities and weighted average strike prices by expected maturity dates for options used by the Company to manage natural gas price risk. These options provide for the Company to receive monthly payments from other parties when a variable price falls below an established floor or "strike" price. At September 30, 2001, the Company held no options with maturity dates extending beyond 2003.

OPTIONS (PUTS) PURCHASED

	Expected Maturity Date		
	2002	2003	Total
Natural Gas			
Notional Quantities (Equivalent Bcf)	2.5	0.2	2.7
Weighted Average Strike Price (per Mcf)	$4.12	$3.98	$4.11

At September 30, 2001, the Company would have received from the respective counterparties an aggregate of approximately $4.7 million to terminate these options.

At September 30, 2000, the Company had purchased natural gas options covering 31.1 Bcf at a weighted average strike price of $4.76 per Mcf. The Company had also sold natural gas options covering 37.9 Bcf at a weighted average strike price of $4.76 per Mcf and sold crude oil options covering 368,000 bbls at a weighted average strike price of $15.25 per bbl. The significant decrease in the amount of options outstanding at September 30, 2001 compared to September 30, 2000 primarily reflects a change in hedging strategy by the Company's Energy Marketing segment, which eliminated its use of options in 2001. At September 30, 2001, the Energy Marketing segment was using only futures contracts to manage the market risk associated with fluctuations in the price of natural gas. The options outstanding at September 30, 2001 were purchased by the Company's Exploration and Production segment.

The following table discloses the net notional quantities, 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, 2001, the Company held no futures contracts with maturity dates extending beyond 2003.

FUTURES CONTRACTS

	Expected Maturity Date		
	2002	**2003**	**Total**
Net Contract Volumes Purchased (Equivalent Bcf)	11.4	1.8	13.2
Weighted Average Contract Price (per Mcf)	$4.16	$4.32	$4.17
Weighted Average Settlement Price (per Mcf)	$2.83	$3.41	$2.89

At September 30, 2001, the Company would have had to pay $15.3 million to terminate these futures contracts.

At September 30, 2000, the Company had futures contracts covering 3.9 Bcf (net short position) at a weighted average contract price of $4.20 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 derivative financial instruments. At September 30, 2001, the Company's credit risk amounted to $36.4 million of net fair value that was owed to the Company for its price swap agreements, no cost collars and puts. There are five counterparties that comprise this credit risk, with the minimum and maximum credit risk from any of the counterparties being 9% and 45%, respectively, of the total fair value at September 30, 2001. One of the counterparties, Enron, representing 29% of the total fair value at September 30, 2001, filed for bankruptcy protection subsequent to September 30, 2001. The bankruptcy filing effectively terminated the natural gas and crude oil price swap agreements as well as the crude oil no cost collars that the Company had entered into with Enron. The natural gas price swap agreements that were terminated covered 8.7 Bcf of production at a weighted average fixed rate of $4.19 per Mcf through the end of 2002. The crude oil price swap agreements that were terminated covered 645,000 bbls of production in 2002 at a weighted average fixed rate of $19.13 per bbl and 135,000 bbls of production in 2003 at a weighted average fixed rate of $19.10 per bbl. The crude oil no cost collars covered 80,000 bbls of production in 2002 at a weighted average ceiling price of $28.10 per bbl and a weighted average floor price of $21.00 per bbl. The Company replaced the Enron natural gas price swap agreements with natural gas no cost collars with another counterparty. The new natural gas no cost collars cover 7.5 Bcf of production in 2002 at a weighted average ceiling price of $4.21 per Mcf and a weighted average floor price of $2.15 per Mcf. In the first quarter of 2002, the Company expects to establish a reserve for up to a maximum amount of $10.7 million for what Enron owed the Company at the time of the termination of the derivative financial instruments (December 3, 2001).* In accordance with SFAS 133, the amount of Accumulated Other Comprehensive Income associated with these cash flow hedges will be reclassified to the Consolidated Statement of Income when the hedged physical transactions occur, the majority of which will occur in 2002, as disclosed above.

Exchange Rate Risk

The International segment's investment in the Czech Republic is valued in Czech korunas, and, as such, this investment is subject to currency exchange risk when the Czech korunas are translated into U.S. dollars. 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. At September 30, 2001 compared to September 30, 2000, the Czech koruna was higher in value in relation to the U.S. dollar resulting in a $7.7 million positive adjustment to the Cumulative Foreign Currency Translation Adjustment (CTA) (a component of Accumulated Other Comprehensive Income/Loss). At September 30, 2001 compared to September 30, 2000, the Canadian dollar was lower in value in relation to the U.S. dollar resulting in a $14.9 million negative adjustment to the CTA. Further valuation changes to the Czech koruna and Canadian dollar would result in corresponding positive or negative adjustments to the CTA. Management cannot predict whether the Czech koruna or Canadian dollar will increase or decrease in value against the U.S. dollar.*

Interest Rate Risk

The Company's exposure to interest rate risk primarily consists of short-term debt instruments. At September 30, 2001, these instruments included short-term bank loans and commercial paper totaling $459.9 million (domestically). The interest rate on these short-term bank loans and commercial paper approximated 3.3% at September 30, 2001. The Company's short-term debt instruments also included $29.8 million of short-term bank loans in Canada and the Czech Republic at September 30, 2001. The weighted average interest rates on the Canadian and Czech Republic loans approximated 3.9% and 5.5%, respectively, at September 30, 2001.

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, 2001:

	Principal Amounts by Expected Maturity Dates						
(Millions of Dollars)	2002	2003	2004	2005	2006	Thereafter	Total
National Fuel Gas Company							
Long-Term Fixed Rate Debt	$100	$150	$225	$ —	$ —	$649	$1,124
Weighted Average Interest Rate Paid	6.2%	7.3%	7.3%	—%	—%	7.0%	7.0%
Fair Value = $1,154.7 million							
Other Notes							
Long-Term Debt (1)	$9.4	$11.1	$3.9	$3.9	$3.6	$0.2	$32.1
Weighted Average Interest Rate Paid	5.5%	5.8%	6.3%	6.3%	6.3%	6.2%	5.9%
Fair Value = $32.1 million							

(1) $18.7 million is variable rate debt; $13.4 million is fixed rate debt.

The Company utilizes an interest rate swap to eliminate interest rate fluctuations on its CZK 586,993,000 term loan ($15.8 million at September 30, 2001), which carries a variable interest rate of six month Prague Interbank Offered Rate (PRIBOR) plus 0.475%. Under the terms of the interest rate swap, which extends until 2002, the Company pays a fixed rate of 8.31% and receives a floating rate of six month PRIBOR. The Company would have paid approximately $0.6 million to settle the interest rate swap at September 30, 2001.

Rate Matters

Utility Operation

New York Jurisdiction

On October 11, 2000, the NYPSC approved a settlement agreement (Agreement) between Distribution Corporation, Staff of the Department of Public Service, the New York State Consumer Protection Board and Multiple Intervenors (an advocate for large commercial and industrial customers) that establishes rates for a three-year period beginning October 1, 2000. The Agreement provides that customers will receive a bill credit of $17.6 million in the first year, of which $7.6 million relates to customers' share of earnings accumulated under previous settlements. The credit will be reduced to $5.0 million in the second year, and in the third and subsequent years the credit will remain at $5.0 million unless the Company can demonstrate that it is no longer justified. Also, earnings beyond a target level of 11.5% return on equity will be shared equally between shareholders and ratepayers. The Agreement provides further that the Company and interested parties will resume discussions to address the NYPSC's competition initiatives, including changes to "customer choice" transportation services, among other things. Those discussions commenced in November 2000 and ultimately produced an interim "Joint Proposal," or settlement agreement, addressing several discrete issues of interest to the parties and the NYPSC. In an order issued on May 30, 2001, the NYPSC adopted the parties' Joint Proposal. As recommended by the parties, the Joint Proposal modifies Distribution Corporation's operations relating to transportation services and transactions with marketers and producers of indigenous natural gas. Under the Joint Proposal, the parties also agreed to continue negotiations to implement additional features of the NYPSC's restructuring initiative (described below). Those confidential discussions, dubbed "Phase III negotiations," are continuing. The Joint Proposal makes no changes in Distribution Corporation's revenue requirement or other such matters addressed in the above-described settlement agreement.

On November 3, 1998, the NYPSC issued its *Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment* (Policy Statement). The Policy Statement sets forth the NYPSC's "vision" on "how best to ensure a competitive market for natural gas in New York." The Policy Statement, which sets forth numerous achievement goals, has been regarded as the Commission's template for restructuring of the gas industry.

The Policy Statement provides that the most effective way to establish a competitive market in gas supply is "for local distribution companies to cease selling gas." The NYPSC indicated in its order that it hopes to accomplish that objective over a three-to-seven year transition period from the date the Policy Statement was issued, taking into account "statutory requirements" and the individual needs of each local distribution company (LDC).* The Policy Statement directs Staff to schedule "discussions" with each LDC on an "individualized plan that would effectuate our vision." In preparation for negotiations, LDCs will be required to address issues such as a strategy to hold new capacity contracts to a minimum, a long-term rate plan with a goal of reducing or freezing rates, and a plan for further unbundling. In addition, Staff was instructed to hold collaborative sessions with multiple parties to discuss generic issues including reliability and market power regulation. Distribution Corporation has participated in the collaborative sessions. These collaborative sessions have not yet produced a consensus document on all issues before the NYPSC. Distribution Corporation will continue to participate in all future collaborative sessions.*

As an outgrowth of the Policy Statement, the NYPSC issued an *Order Directing Expedited Consideration of Rate Unbundling* on March 29, 2001 (Unbundling Order). The Unbundling Order directs the state's electric and gas utilities, including Distribution Corporation, to submit cost studies for "bottom-up" unbundling, which as described by the NYPSC, "begins with the total costs of the utility's business and then assigns those costs to the various functions, some of which are expected to become competitively available." This is in contrast to methods used for establishing "back-out" credits, although the result is essentially the same: competitive functions are identified and priced in order to subsidize market entry for marketers. Numerous parties met for several collaborative sessions and were unable to reach consensus on the methodology for the studies. Accordingly, briefs were filed and a decision on the appropriate methodology to use will be issued by the NYPSC at a later date. Distribution Corporation has no objection to the NYPSC's authority to order unbundling cost studies, but to the extent any legally-mandated utility functions are identified as "competitive," there is a possibility that stranded costs may be incurred. While at this juncture the NYPSC has not indicated that stranded cost recovery would be denied, in whole or in part, the issue remains open for consideration in individual utility proceedings. At this time, Distribution Corporation is unable to ascertain the outcome of this proceeding.*

On July 23, 2001, the NYPSC ordered implementation of an initial set of electronic data interchange (EDI) datasets for electronic exchange of retail access data in New York (EDI Order). As described by the NYPSC, EDI is the computer-to-computer exchange of routine business information in a standard form. The NYPSC believes that EDI is necessary to develop uniform data exchange protocol for the state's customer choice initiatives. The EDI Order adopts modified enrollment and historical usage datasets initially prepared by an EDI working group involving utilities, marketers and other interests. The Order identifies required changes to uniform business practices and also adopts Web Site Design Principles and EDI testing plans. Initial EDI implementation is ordered for calendar year-end 2001 following completion of EDI testing. Phased testing of EDI began during the fourth quarter of calendar 2001. The NYPSC also directs development of datasets governing billing and payment processing based upon the recommendations of a national group of stakeholders. EDI datasets governing billing are now under development and will be completed in the first quarter of calendar 2002 and implemented thereafter.

The NYPSC continues to address, through various proceedings and "collaboratives," upstream pipeline capacity issues arising from the restructuring. Currently Distribution Corporation remains authorized to release upstream intermediate capacity to marketers serving former sales customers. Costs relating to retained upstream transmission capacity are recovered through a transition cost surcharge. At this time, Distribution Corporation does not foresee any material changes to upstream capacity requirements in the near term.*

On May 15, 2000, the New York State tax law was amended to phase out the long-running tax on utility gross revenues beginning January 1, 2001. Offsetting the scheduled reductions, however, is the imposition of a net income based tax on the same utilities. In an order issued on December 21, 2000, the NYPSC adopted a recommendation providing that utilities be kept whole for any tax increases resulting from implementation of the changes. Toward that end, the report proposed that the mechanism in rates currently used for recovery of the gross revenue tax would be utilized to collect the new income tax. To the extent a utility's income tax liability exceeded the amount collectible through the existing gross revenue tax recovery mechanism, deferral accounting would be authorized.

Pennsylvania Jurisdiction

Distribution Corporation currently does not have a rate case on file with the Pennsylvania Public Utility Commission (PaPUC). Management will continue to monitor its financial position in the Pennsylvania jurisdiction to determine the necessity of filing a rate case in the future.

A natural gas restructuring bill was signed into law on June 22, 1999. Entitled the Natural Gas Choice and Competition Act (Act), the new law requires all Pennsylvania LDCs to file tariffs designed to provide retail customers with direct access to competitive gas markets. Distribution Corporation submitted its compliance filing on October 1, 1999 for an effective date on or about July 1, 2000. The filing largely mirrored Distribution Corporation's System Wide Energy Select program previously in effect, which substantially complied with the Act's requirements. After negotiations with PaPUC Staff and intervenors, a settlement was reached with all parties except for the Pennsylvania Office of Consumer Advocate (OCA). The settlement parties generally agreed that Distribution Corporation's proposal needed only modest changes to meet the requirements of the Act. Hearings were held and briefs filed on OCA's open issues. In a Recommended Decision issued on March 31, 2000, the Administrative Law Judge rejected the OCA's arguments and recommended approval of the settlement agreement. On June 29, 2000, the PaPUC entered an Opinion and Order adopting the settlement, with immaterial changes. Distribution Corporation's restructured rates and services became effective on July 1, 2000.

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.

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.

Other Matters

Environmental Matters

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 in the range of $5.4 million to $6.4 million.* The minimum liability of $5.4 million has been recorded on the Consolidated Balance Sheet at September 30, 2001. Other than discussed in Note H (referred to below), the Company is currently not aware of any material additional exposure to environmental liabilities. However, adverse changes in environmental regulations or other factors could impact the Company.* 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.

For further discussion refer to Note H - Commitments and Contingencies under the heading "Environmental Matters" in Item 8 of this report.

New Accounting Pronouncements

In 2001, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 141, "Business Combinations" (SFAS 141), SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142) and SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). For a discussion of SFAS 141, SFAS 142 and SFAS 143 and their impact on the Company, see disclosure in Note A – Summary of Significant Accounting Policies in Item 8 of this report.

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 those which are designated with an asterisk ("*"), are "forward-looking" statements as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties, but there can be no assurance that management's expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Changes in economic conditions, including economic disruptions caused by terrorist activities;
2. Changes in demographic patterns and weather conditions;
3. Changes in the availability and/or price of natural gas and oil;
4. Inability to obtain new customers or retain existing ones;
5. Significant changes in competitive factors affecting the Company;
6. Governmental/regulatory actions, initiatives and proceedings, including those affecting acquisitions, financings, allowed rates of return, industry and rate structure, franchise renewal, and environmental/safety requirements;
7. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;
8. Significant changes from expectations in actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs;
9. The nature and projected profitability of pending and potential projects and other investments;
10. Occurrences affecting the Company's ability to obtain funds from operations, debt or equity to finance needed capital expenditures and other investments;
11. Uncertainty of oil and gas reserve estimates;
12. Ability to successfully identify and finance oil and gas property acquisitions and ability to operate and integrate existing and any subsequently acquired business or properties;
13. Ability to successfully identify, drill for and produce economically viable natural gas and oil reserves;
14. Significant changes from expectations in the Company's actual production levels for natural gas or oil;
15. Changes in the availability and/or price of derivative financial instruments;

16. Changes in the price of natural gas or oil and the related effect given the accounting treatment or valuation of financial instruments;
17. Inability of the various counterparties to meet their obligations with respect to the Company's financial instruments;
18. 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;
19. Significant changes in tax rates or policies or in rates of inflation or interest;
20. Significant changes in the Company's relationship with its employees and contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur; or
21. Changes in accounting principles or the application of such principles to the Company.

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

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 K - Quarterly Financial Data (unaudited) and Note M - Supplementary Information for Oil and Gas Producing Activities, appears under this Item, and reference is made thereto.

Report of Management

Management is responsible for the preparation and integrity of the Company's financial statements. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America and necessarily include some amounts that are based on management's best estimates and judgment.

The Company maintains a system of internal accounting and administrative controls and an ongoing program of internal audits that management believes provide reasonable assurance that assets are safeguarded and that transactions are properly recorded and executed in accordance with management's authorization. The Company's financial statements have been examined by our independent accountants, PricewaterhouseCoopers LLP, which also conducts a review of internal controls to the extent required by auditing standards generally accepted in the United States of America.

The Audit Committee of the Board of Directors, composed solely of outside directors, meets with management, internal auditors and PricewaterhouseCoopers LLP to review planned audit scope and results and to discuss other matters affecting internal accounting controls and financial reporting. The independent accountants have direct access to the Audit Committee and periodically meet with it without management representatives present.

Report of Independent Accountants

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2001, 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 auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit 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.

PricewaterhouseCoopers LLP

Buffalo, New York
October 24, 2001, except for
Note F, as to which the date is
December 3, 2001

Consolidated Statements of Income and Earnings Reinvested in the Business

	Year Ended September 30 (Thousands of Dollars, Except Per Common Share Amounts)	2001	2000	1999
Income	**Operating Revenues**	$2,100,352	$1,425,277	$1,263,274
	Operating Expenses			
	Purchased Gas	1,045,805	503,617	405,925
	Fuel Used in Heat and Electric Generation	54,968	54,893	55,788
	Operation	343,693	326,933	304,919
	Maintenance	20,625	23,450	23,881
	Property, Franchise and Other Taxes	83,730	78,878	91,146
	Depreciation, Depletion and Amortization	174,914	142,170	124,778
	Impairment of Oil and Gas Producing Properties	180,781	—	—
	Income Taxes	37,106	77,068	64,829
		1,941,622	1,207,009	1,071,266
	Operating Income	158,730	218,268	192,008
	Other Income	15,256	10,408	12,343
	Income Before Interest Charges and Minority Interest in Foreign Subsidiaries	173,986	228,676	204,351
	Interest Charges			
	Interest on Long-Term Debt	81,851	67,195	65,402
	Other Interest	25,294	32,890	22,296
		107,145	100,085	87,698
	Minority Interest in Foreign Subsidiaries	(1,342)	(1,384)	(1,616)
	Net Income Available for Common Stock	65,499	127,207	115,037
Earnings Reinvested in the Business	Balance at Beginning of Year	525,847	472,517	428,112
		591,346	599,724	543,149
	Dividends on Common Stock	77,858	73,877	70,632
	Balance at End of Year	$513,488	$525,847	$472,517
	Earnings Per Common Share:			
	Basic	$0.83	$1.63	$1.49
	Diluted	$0.82	$1.61	$1.47
	Weighted Average Common Shares Outstanding:			
	Used in Basic Calculation	79,053,444	78,233,842	77,327,962
	Used in Diluted Calculation	80,361,258	79,166,200	78,083,456

See Notes to Consolidated Financial Statements

Consolidated Balance Sheets

At September 30 (Thousands of Dollars)	2001	2000
Assets		
Property, Plant and Equipment	**$4,273,716**	$3,829,637
Less - Accumulated Depreciation, Depletion and Amortization	**1,493,003**	1,146,246
	2,780,713	2,683,391
Current Assets		
Cash and Temporary Cash Investments	**36,227**	32,125
Receivables – Net	**131,726**	121,639
Unbilled Utility Revenue	**25,375**	27,105
Gas Stored Underground	**83,231**	55,795
Materials and Supplies - at average cost	**33,710**	25,145
Unrecovered Purchased Gas Costs	**4,113**	29,681
Prepayments	**39,520**	39,150
	353,902	330,640
Other Assets		
Recoverable Future Taxes	**86,586**	84,199
Unamortized Debt Expense	**19,796**	19,841
Other Regulatory Assets	**23,253**	24,804
Deferred Charges	**9,136**	12,985
Fair Value of Derivative Financial Instruments	**37,585**	—
Other	**134,595**	95,171
	310,951	237,000
	$3,445,566	$3,251,031

See Notes to Consolidated Financial Statements

Capitalization and Liabilities

At September 30 (Thousands of Dollars)	2001	2000
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value Authorized - 200,000,000 Shares; Issued and Outstanding - 79,406,105 Shares and 78,659,606 Shares, Respectively	**$79,406**	$78,660
Paid In Capital	**430,618**	412,887
Earnings Reinvested in the Business	**513,488**	525,847
Total Common Shareholder Equity Before Items Of Other Comprehensive Loss	**1,023,512**	1,017,394
Accumulated Other Comprehensive Loss	**(20,857)**	(29,957)
Total Comprehensive Shareholders' Equity	**1,002,655**	987,437
Long-Term Debt, Net of Current Portion	**1,046,694**	953,622
Total Capitalization	**2,049,349**	1,941,059
Minority Interest in Foreign Subsidiaries	**22,324**	23,031
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	**489,673**	619,502
Current Portion of Long-Term Debt	**109,435**	11,262
Accounts Payable	**118,505**	88,853
Amounts Payable to Customers	**51,223**	9,583
Other Accruals and Current Liabilities	**94,634**	79,370
	863,470	808,570
Deferred Credits		
Accumulated Deferred Income Taxes	**340,559**	326,994
Taxes Refundable to Customers	**16,865**	14,410
Unamortized Investment Tax Credit	**9,599**	9,951
Other Deferred Credits	**126,319**	114,451
Fair Value of Derivative Financial Instruments	**17,081**	12,565
	510,423	478,371
Commitments and Contingencies	**—**	—
	$3,445,566	$3,251,031

See Notes to Consolidated Financial Statements

Consolidated Statement of Cash Flows

	Year Ended September 30 (Thousands of Dollars)	2001	2000	1999
Operating Activities	Net Income Available for Common Stock	$65,499	$127,207	$115,037
	Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities			
	Impairment of Oil and Gas Producing Properties	180,781	—	—
	Depreciation, Depletion and Amortization	174,914	142,170	124,778
	Deferred Income Taxes	(55,849)	41,858	14,030
	Minority Interest in Foreign Subsidiaries	1,342	1,384	1,616
	Other	6,553	4,540	7,018
	Change in:			
	Receivables and Unbilled Utility Revenue	(2,299)	(26,336)	(18,161)
	Gas Stored Underground and Materials and Supplies	(37,054)	(13,707)	(7,280)
	Unrecovered Purchased Gas Costs	25,568	(25,105)	1,740
	Prepayments	(399)	(3,420)	(15,322)
	Accounts Payable	20,419	(16,489)	22,871
	Amounts Payable to Customers	41,640	3,649	153
	Other Accruals and Current Liabilities	13,969	(10,233)	10,931
	Other Assets	(34,229)	763	(906)
	Other Liabilities	13,289	11,965	10,999
	Net Cash Provided by Operating Activities	414,144	238,246	267,504
Investing Activities	Capital Expenditures	(292,706)	(269,371)	(256,120)
	Investment in Subsidiaries, Net of Cash Acquired	(90,567)	(123,809)	(5,774)
	Investment in Partnerships	(1,830)	(4,442)	(3,633)
	Other	(2,940)	13,283	6,687
	Net Cash Used in Investing Activities	(388,043)	(384,339)	(258,840)
Financing Activities	Change in Notes Payable to Banks and Commercial Paper	(143,397)	226,477	67,195
	Net Proceeds from Issuance of Long-Term Debt	210,221	149,334	198,217
	Reduction of Long-Term Debt	(23,052)	(167,426)	(213,849)
	Proceeds from Issuance of Common Stock	11,545	14,278	10,735
	Dividends Paid on Common Stock	(76,671)	(73,046)	(69,878)
	Dividends Paid to Minority Interest	—	(152)	(246)
	Net Cash Provided by (Used in) Financing Activities	(21,354)	149,465	(7,826)
	Effect of Exchange Rates on Cash	(645)	(469)	(2,053)
	Net Increase (Decrease) in Cash and Temporary Cash Investments	4,102	2,903	(1,215)
	Cash and Temporary Cash Investments at Beginning of Year	32,125	29,222	30,437
	Cash and Temporary Cash Investments at End of Year	$36,227	$32,125	$29,222
	Supplemental Disclosure of Cash Flow Information			
	Cash Paid For:			
	Interest	$97,259	$97,042	$75,813
	Income Taxes	77,662	41,928	48,995

See Notes to Consolidated Financial Statements

Consolidated Statement of Comprehensive Income

Year Ended September 30 (Thousands of Dollars)	2001	2000	1999
Net Income Available for Common Stock	**$65,499**	$127,207	$115,037
Other Comprehensive Income, Before Tax:			
Foreign Currency Translation Adjustment	**(7,158)**	(27,463)	(11,737)
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	**(712)**	2,441	706
Unrealized Gain on Derivative Financial Instruments Arising During the Period	**58,355**	—	—
Reclassification Adjustment for Realized Losses on Derivative Financial Instruments in Net Income	**83,218**	—	—
Reclassification Adjustment for Realized Gains on Securities Available for Sale in Net Income	**—**	(103)	—
Other Comprehensive Income (Loss), Before Tax:	**133,703**	(25,125)	(11,031)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	**(249)**	855	247
Income Tax Expense Related to Unrealized Gain on Derivative Financial Instruments Arising During the Period	**23,053**	—	—
Reclassification Adjustment for Income Tax Benefit on Realized Losses on Derivative Financial Instruments in Net Income	**32,032**	—	—
Reclassification Adjustment for Income Tax Expense on Realized Gains on Securities Available for Sale in Net Income	**—**	(36)	—
Income Taxes – Net	**54,836**	819	247
Other Comprehensive Income (Loss), Before Cumulative Effect, Net of Tax	**78,867**	(25,944)	(11,278)
Cumulative Effect of Change in Accounting, Net of Tax	**(69,767)**	—	—
Other Comprehensive Income (Loss), After Cumulative Effect, Net of Tax	**9,100**	(25,944)	(11,278)
Comprehensive Income	**$74,599**	$101,263	$103,759

See Notes to Consolidated Financial Statements

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.

Stock Split

Effective September 7, 2001, the Company's common stock was split two-for-one. All references in the consolidated financial statements referring to shares, share prices, per share amounts and stock plans have been adjusted retroactively to give effect to the two-for-one common stock split.

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.

In the International segment, rates charged for the sale of thermal energy and electric energy at the retail level are subject to regulation and audit in the Czech Republic by the Czech Ministry of Finance. The regulation of electric energy rates at the retail level indirectly impacts the rates charged by the International segment for its electric energy sales at the wholesale level.

Revenues

Revenues are recorded 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.

Unrecovered Purchased Gas Costs and Refunds

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.

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

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. As a result of low oil and gas prices, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling for the Company's Canadian properties at September 30, 2001. The Company was required to recognize an impairment of its oil and gas producing properties in the quarter ended September 30, 2001. This charge amounted to $180.8 million (pre tax) and reduced net income for 2001 by $104.0 million ($1.32 per common share; basic, $1.29 per common share, diluted).

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

Depreciation, depletion and amortization are computed by application of either the straight-line method or the units of production method, in amounts sufficient to recover costs over the estimated service lives of property in service, and for oil and gas properties, based on quantities produced in relation to proved reserves. The costs of unevaluated oil and gas properties are excluded from this computation. For timber properties, depletion, determined on a property by property basis, is charged to operations based on the annual amount of timber cut in relation to the total amount of recoverable timber. The provisions for depreciation, depletion and amortization, as a percentage of average depreciable property, were 4.7% in 2001, 4.2% in 2000 and 4.1% in 1999 on a consolidated basis.

Cumulative Effect of Change in Accounting

Effective October 1, 2000, the Company adopted the Financial Accounting Standards Board's (FASB) Statement of Financial Accounting Standards (SFAS) No. 133, "Accounting for Derivative Instruments and Hedging Activities" (SFAS 133) as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities – Deferral of the Effective Date of FASB Statement No. 133" and by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities, an amendment of Statement 133" (collectively, SFAS 133). The cumulative effect of this change decreased other comprehensive income by $69.8 million (after tax) at adoption on October 1, 2000. The cumulative effect of this change did not have a material impact on net income at adoption on October 1, 2000. Of the cumulative effect recorded in other comprehensive income, $46.3 million (after tax) was reclassified into the Consolidated Statement of Income during 2001. The derivative financial instruments that comprise the cumulative effect recorded in other comprehensive income have been designated and qualify as cash flow hedges, as discussed below.

Financial Instruments

Unrealized gains or losses from the Company's investments in marketable equity securities are recorded as a component of Accumulated Other Comprehensive Income (Loss). Reference is made to Note F - Financial Instruments for further discussion.

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments can be categorized as price swap agreements, no cost collars, options and futures contracts. The Company also uses an interest rate swap to eliminate interest rate fluctuations on certain variable rate debt. As discussed above, on October 1, 2000 the Company adopted SFAS 133. In accordance with the provisions of these standards, 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 Sheet as either an asset or a liability labeled "Fair Value of 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 Sheet. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statement of Income. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2001. 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, as applicable, 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 Statement of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheet 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 Statement 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 2001.

In the case of the no cost collars and options used by the Company, the fair value of these instruments consisted of time value and intrinsic value. The exclusion of time value from the Company's effectiveness tests during 2001 resulted in a $4.4 million gain that was recorded in operating revenues on the Consolidated Statement of Income.

Prior to October 1, 2000, gains or losses from price swap agreements and no cost collars were accrued in operating revenues on the Consolidated Statement of Income at the contract settlement dates. Gains or losses from futures contracts that were designated as hedges were recorded in other deferred credits or deferred debits until the hedged commodity transaction occurred, at which point they were reflected in operating revenues on the Consolidated Statement of Income. For options that were designated as hedges, premiums were amortized on a straight-line basis over the life of the option. Gains or losses resulting from the exercise of options that were designated as hedges were reflected in operating revenues on the Consolidated Statement of Income when the hedged commodity transaction occurred. Options and futures that were not designated as hedges were marked-to-market on a quarterly basis with gains or losses recorded in operating revenues on the Consolidated Statement of Income. In the case of the interest rate swap, gains and losses were accrued in interest charges at the contract settlement dates.

While the accounting standards for derivative financial instruments in 2001 are different from those used in 2000, the liabilities that were recorded for derivative financial instruments at September 30, 2000 have been reclassified to "Fair Value of Derivative Financial Instruments" on the September 30, 2000 Consolidated Balance Sheet. Reference is made to Note F - Financial Instruments for further discussion of derivative financial instruments.

Accumulated Other Comprehensive Income (Loss)

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

Year Ended September 30 (Thousands)	**2001**	**2000**
Cumulative Foreign Currency Translation Adjustment	**$(39,093)**	$(31,935)
Net Unrealized Gain on Derivative Financial Instruments	**16,721**	—
Net Unrealized Gain on Securities Available for Sale	**1,515**	1,978
Accumulated Other Comprehensive Loss	**$(20,857)**	$(29,957)

At September 30, 2001, it is estimated that $16.1 million of the net unrealized gain on derivative financial instruments shown in the table above will be reclassified into the Consolidated Statement of Income during 2002.

Gas Stored Underground - Current

In the Utility segment, gas stored underground - current in the amount of $69.5 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 2001, 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 $4.0 million at September 30, 2001. All other gas stored underground - current is carried at lower of cost or market on either an average cost or first-in, first-out method.

Unamortized Debt Expense

Costs associated with the issuance of debt by the Company are deferred and amortized over the lives of the related issues. 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. 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. No provision has been made for domestic income taxes applicable to undistributed earnings of foreign subsidiaries as the amounts are considered to be permanently reinvested outside the United States.

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.

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 Statement of Income reflects the potential dilution as a result of these stock options as determined using the Treasury Stock Method.

New Accounting Pronouncements

In 2001, the FASB issued SFAS No. 141, "Business Combinations" (SFAS 141), SFAS No. 142, "Goodwill and Other Intangible Assets" (SFAS 142) and SFAS No. 143, "Accounting for Asset Retirement Obligations" (SFAS 143). SFAS 141 requires that all business combinations initiated after June 30, 2001 be accounted for by the purchase method. It also requires disclosure of the primary reasons for a business combination and the allocation of the purchase price paid to the assets acquired and liabilities assumed by major balance sheet caption. Additional disclosure would be required when goodwill and intangible assets represent a significant portion of the purchase price paid. SFAS 142 addresses financial accounting and reporting for acquired goodwill and other intangible assets. Under this standard, goodwill and intangible assets that have indefinite useful lives will not be amortized but rather will be tested at least annually for impairment. Intangible assets that have finite useful lives will continue to be amortized over their useful lives, but the amortization period will not be limited to a certain period of time. SFAS 142 requires that the Company adopt this standard by October 1, 2002. However, goodwill and intangible assets acquired after June 30, 2001 will be subject immediately to the provisions of SFAS 142. SFAS 143 requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the entity capitalizes the cost by increasing 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. When the liability is settled, the entity either settles the obligation for its recorded amount or incurs a gain or loss upon settlement. SFAS 143 requires that the Company adopt this standard by October 1, 2002, with earlier application encouraged. Management is currently evaluating the impact of SFAS 142 and SFAS 143 on the financial condition and results of operations of the Company.

NOTE B Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

At September 30 (Thousands)	2001	2000
Regulatory Assets:		
Recoverable Future Taxes (Note C)	**$86,586**	$84,199
Unrecovered Purchased Gas Costs (Note A)	**4,113**	29,681
Unamortized Debt Expense (Note A)	**11,738**	13,454
Pension and Post-Retirement Benefit Costs (Note G)	**21,065**	23,656
Other	**2,188**	1,148
Total Regulatory Assets	**125,690**	152,138
Regulatory Liabilities:		
Amounts Payable to Customers (Note A)	**51,223**	9,583
New York Rate Settlements [1]	**27,630**	21,315
Taxes Refundable to Customers (Note C)	**16,865**	14,410
Pension and Post-Retirement Benefit Costs [1] (Note G)	**33,829**	24,725
Other [1]	**7,498**	2,975
Total Regulatory Liabilities	**137,045**	73,008
Net Regulatory Position	**$(11,355)**	$79,130

(1) Included in Other Deferred Credits 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 State of New York Public Service Commission (NYPSC). The rate settlements provide for a sharing mechanism, whereby earnings above a specified return on equity (11.5% and 12% for 2001 and 2000, respectively) are to be shared equally between shareholders and ratepayers. As a result of this sharing mechanism, the Company had liabilities of $5.8 million and $11.2 million at September 30, 2001 and

2000, respectively. At September 30, 2000, $7.6 million of the earnings sharing liability was included in Amounts Payable to Customers, to reflect the amounts that were passed back to customers in 2001. Other aspects of the settlements include a special reserve of $8.2 million and $7.8 million at September 30, 2001 and 2000, respectively, to be applied against the Company's incremental costs resulting from the NYPSC's gas restructuring effort and a "refund pool" of $6.0 million and $5.6 million at September 30, 2001 and 2000, respectively. The refund pool is an accumulation of certain refunds from upstream pipeline companies and certain credits which can be used to offset certain specific expense items. Various other regulatory liabilities have also been created through the New York rate settlements and amounted to $7.7 million and $4.2 million at September 30, 2001 and 2000, respectively.

NOTE C Income Taxes

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

Year Ended September 30 (Thousands)	2001	2000	1999
Operating Expenses:			
Current Income Taxes -			
Federal	**$67,429**	$26,352	$43,467
State	**21,330**	13,067	6,215
Foreign	**4,196**	(4,209)	1,116
Deferred Income Taxes -			
Federal	**18,444**	29,604	11,149
State	**431**	2,495	1,244
Foreign	**(74,724)**	9,759	1,638
	37,106	77,068	64,829
Other Income:			
Deferred Investment Tax Credit	**(348)**	(1,051)	(729)
Minority Interest in Foreign Subsidiaries	**(614)**	(259)	(642)
Total Income Taxes	**$36,144**	$75,758	$63,458

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

Year Ended September 30 (Thousands)	2001	2000	1999
U.S.	**$267,270**	$182,813	$169,038
Foreign	**(165,627)**	20,152	9,457
	$101,643	$202,965	$178,495

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 (Thousands)	2001	2000	1999
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	**$35,575**	$71,038	$62,473
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	**14,145**	10,115	4,848
Foreign Tax Rate Differential	**(13,172)**	(1,762)	(1,198)
Depreciation	**1,790**	1,925	1,872
Miscellaneous	**(2,194)**	(5,558)	(4,537)
Total Income Taxes	**$36,144**	$75,758	$63,458

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

At September 30 (Thousands)	2001	2000
Deferred Tax Liabilities:		
Property, Plant and Equipment	$389,879	$375,660
Other	27,047	13,322
Total Deferred Tax Liabilities	416,926	388,982
Deferred Tax Assets:		
Deferred Gas Costs	(20,178)	10,454
Other	(56,189)	(72,442)
Total Deferred Tax Assets	(76,367)	(61,988)
Total Net Deferred Income Taxes	$340,559	$326,994

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 $16.9 million and $14.4 million at September 30, 2001 and 2000, 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 $86.6 million and $84.2 million at September 30, 2001 and 2000, respectively.

NOTE D Capitalization

SUMMARY OF CHANGES IN COMMON STOCK EQUITY

	Common Stock				
(Thousands, Except Per Share Amounts)	Shares	Amount	Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
Balance at September 30, 1998	76,938	$76,938	$377,770	$428,112	$7,265
Net Income Available for Common Stock				115,037	
Dividends Declared on Common Stock ($0.92 Per Share)				(70,632)	
Other Comprehensive Loss, Net of Tax					(11,278)
Common Stock Issued Under Stock and Benefit Plans	736	736	15,345		
Balance at September 30, 1999	77,674	77,674	393,115	472,517	(4,013)
Net Income Available for Common Stock				127,207	
Dividends Declared on Common Stock ($0.95 Per Share)				(73,877)	
Other Comprehensive Loss, Net of Tax					(25,944)
Acquisition of Natural Gas Assets	110	110	2,702		
Common Stock Issued Under Stock and Benefit Plans	876	876	17,070		
Balance at September 30, 2000	78,660	78,660	412,887	525,847	(29,957)
Net Income Available for Common Stock				65,499	
Dividends Declared on Common Stock ($0.99 Per Share)				(77,858)	
Other Comprehensive Income, Net of Tax					9,100
Common Stock Issued Under Stock and Benefit Plans	746	746	17,731		
Balance at September 30, 2001	79,406	$79,406	$430,618	$513,488[1]	$(20,857)

(1) 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, 2001, $439.1 million of accumulated earnings was free of such limitations.

Common Stock

The Company has various plans which allow shareholders, customers and employees to purchase shares of Company common stock. The National Fuel Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends or make cash investments in the Company's common stock and provides residential customers the opportunity to acquire shares of Company common stock without the payment of any brokerage commissions or service charges in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in Company common stock, in addition to a variety of other investment alternatives. 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 agent.

The Company also has a Director Stock Program under which it issues shares of 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, stock appreciation rights, 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.

For the years ended September 30, 2001, 2000 and 1999, no compensation expense was recognized for options granted under these plans. Had compensation expense for stock options granted under the Company's stock option and stock award plans been determined based on fair value at the grant dates, the Company's net income and earnings per share would have been reduced to the pro forma amounts below:

Year Ended September 30	**2001**	**2000**	**1999**
Net Income *(Thousands)*:			
As reported	**$65,499**	$127,207	$115,037
Pro forma	**$59,108**	$123,107	$111,385
Earnings Per Common Share:			
Basic - As reported	**$0.83**	$1.63	$1.49
Basic - Pro forma	**$0.75**	$1.58	$1.44
Diluted - As reported	**$0.82**	$1.61	$1.47
Diluted - Pro forma	**$0.73**	$1.56	$1.43

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, 1998	5,463,792	$18.40
Granted in 1999	1,506,800	$23.35
Exercised in 1999 [1]	(223,008)	$14.21
Forfeited in 1999	(19,400)	$18.71
Outstanding at September 30, 1999	6,728,184	$19.65
Granted in 2000	1,782,200	$21.87
Exercised in 2000 [1]	(455,484)	$15.08
Forfeited in 2000	(27,800)	$23.08
Outstanding at September 30, 2000	**8,027,100**	**$20.38**
Granted in 2001	**1,787,200**	**$27.61**
Exercised in 2001 [1]	**(372,040)**	**$15.89**
Forfeited in 2001	**(69,574)**	**$22.36**
Outstanding at September 30, 2001	**9,372,686**	**$21.92**
Option shares exercisable at September 30, 2001	**7,269,160**	**$20.43**
Option shares available for future grant at September 30, 2001 [2]	**540,450**	

(1) In connection with exercising these options, 78,850, 116,916 and 33,062 shares were surrendered and canceled during 2001, 2000 and 1999, respectively.
(2) Including shares available for restricted stock grants. Subsequent to September 30, 2001, the shareholders approved an additional 6 million shares available for granting.

The weighted average fair value per share of options granted in 2001, 2000 and 1999 was $5.25, $4.17 and $3.72, 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	2001	2000	1999
Quarterly Dividend Yield	**0.87%**	1.07%	0.97%
Annual Standard Deviation (Volatility)	**20.51%**	19.05%	18.86%
Risk Free Rate	**5.26%**	6.74%	4.74%
Expected Term - in Years	**5.0**	5.5	5.0

The following table summarizes information about options outstanding at September 30, 2001:

Options Outstanding				Options Exercisable	
Range of Exercise Price	Number Outstanding at 9/30/01	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Number Exercisable at 9/30/01	Weighted Average Exercise Price
$11.12 - $16.68	**1,130,542**	**2.9 years**	**$14.84**	**1,130,542**	**$14.84**
$16.69 - $22.24	**3,453,470**	**6.6 years**	**$20.28**	**3,403,470**	**$20.28**
$22.25 - $27.80	**4,788,674**	**7.8 years**	**$24.78**	**2,735,148**	**$22.92**

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 being recorded as compensation expense over the periods during which the vesting restrictions exist. Certificates for shares of restricted stock awarded under the Company's stock options and stock award plans are held by the Company during the periods in which the restrictions on vesting are effective.

The following table summarizes the awards of restricted stock over the past three years:

Year Ended September 30	2001	2000	1999
Shares of Restricted Stock Awarded	4,000	15,178	13,160
Weighted Average Market Price of Stock on Award Date	$27.80	$24.47	$23.03

As of September 30, 2001, 84,738 shares of non-vested restricted stock were outstanding. Vesting restrictions will lapse as follows: 2002 – 16,000 shares; 2003 – 32,610 shares; 2004 – 11,600 shares; 2005 – 9,600 shares; 2006 – 9,600 shares; 2007 – 4,000 shares; and 2009 - 1,328 shares.

Stock Appreciation Rights (SARs) give the grantee the right to cash compensation equal to the appreciation in the market price of Company common stock from the grant date to the exercise date. SARs are marked-to-market each quarter with the related increase or decrease in expense recognized in the income statement. At September 30, 2001, 3,303,308 SARs were outstanding at a weighted average exercise price of $20.71.

Compensation (benefit) expense related to SARs and restricted stock under the Company's stock plans was ($13.4) million, $14.9 million and $1.0 million for the years ended September 30, 2001, 2000 and 1999, respectively. Subsequent to September 30, 2001, the Company canceled substantially all of the SARs, issued non-qualified stock options and eliminated all future awards of SARs under its stock option plans. As a result, future earnings will not be materially impacted by SARs expense.

Redeemable Preferred Stock

As of September 30, 2001, 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 (Thousands)	2001	2000
Debentures:		
7-3/4% due February 2004	$125,000	$125,000
Medium-Term Notes:		
6.00% to 8.48% due February 2000 to August 2027 (1)	999,000	799,000
	1,124,000	924,000
Other Notes	32,129	40,884
Total Long-Term Debt	1,156,129	964,884
Less Current Portion	109,435	11,262
	$1,046,694	$953,622

(1) Includes $50 million of 8.48% medium-term notes due July 2024 which are callable at a redemption price of 105.51% through July 2002. The redemption price will decline in subsequent years. Also includes $100 million of 6.214% medium-term notes due August 2027 which are putable by debt holders only on August 12, 2002, at par. The $100 million of 6.214% medium-term notes are included in the current portion of long-term debt at September 30, 2001.

As of September 30, 2001, the aggregate principal amounts of long-term debt maturing for the next five years and thereafter are as follows: $109.4 million in 2002, $161.1 million in 2003, $228.9 million in 2004, $3.9 million in 2005, $3.6 million in 2006 and $649.2 million thereafter.

NOTE E Short-Term Borrowings

The Company has SEC authorization under the Public Utility Holding Company Act of 1935, as amended, to borrow and have outstanding as much as $750.0 million of short-term debt at any time through December 31, 2002.

The Company historically has borrowed short-term funds either through bank loans or the issuance of commercial paper. As for the former, the Company maintains uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis.

At September 30, 2001, the Company had outstanding short-term notes payable to banks and commercial paper of $289.7 million (domestic = $259.9 million; foreign = $29.8 million) and $200.0 million, respectively. At September 30, 2000, the Company had outstanding notes payable to banks and commercial paper of $419.5 million (domestic = $401.2 million; foreign = $18.3 million) and $200.0 million, respectively.

The weighted average interest rate on domestic notes payable to banks was 3.39% and 6.81% at September 30, 2001 and 2000, respectively. The interest rate on the foreign notes payable to banks was 4.65% and 5.73% at September 30, 2001 and 2000, respectively. The weighted average interest rate on commercial paper was 3.13% and 6.62% at September 30, 2001 and 2000, respectively.

NOTE F Financial Instruments

Fair Values

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

At September 30 (Thousands)	2001 Carrying Amount	2001 Fair Value	2000 Carrying Amount	2000 Fair Value
Long-Term Debt	$1,156,129	$1,186,795	$964,884	$928,066

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 amounts which approximate 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 a 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.

Investments

Other assets includes cash surrender values of insurance contracts and marketable equity securities. The cash surrender values of the insurance contracts amounted to $52.9 million and $49.4 million at September 30, 2001 and 2000, respectively. The marketable equity securities amounted to $10.0 million at both September 30, 2001 and 2000. 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 can be categorized as 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 price quoted on the New York Mercantile Exchange (NYMEX) or a quoted natural gas price in "Inside FERC." These derivative financial instruments are accounted for as cash flow hedges. They are used to lock in a price for the anticipated sale of natural gas and crude oil production in the Exploration and Production segment. At September 30, 2001, the Company had natural gas price swap agreements covering a notional amount of 27.5 Bcf extending through 2003 at a weighted average fixed rate of $3.77 per Mcf. The Company also had crude oil price swap agreements covering a notional amount of 6,643,980 bbls extending through 2003 at a weighted average fixed rate of $22.15 per bbl. At September 30, 2001, the Company would have received a net $18.2 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. They 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, 2001, the Company had no cost collars on natural gas covering a notional amount of 9.2 Bcf extending through 2004 with a weighted average floor price of $4.06 per Mcf and a weighted average ceiling price of $5.36 per Mcf. The Company also had no cost collars on crude oil covering a notional amount of 2,730,000 bbls extending through 2004 with a weighted average floor price of $21.94 per bbl and a weighted average ceiling price of $27.25 per bbl. At September 30, 2001, the Company would have received $13.5 million to terminate the no cost collars.

At September 30, 2001, the Company had purchased options outstanding on natural gas covering a notional amount of 2.7 Bcf extending through 2003 at a weighted average strike price of $4.11 per Mcf. These derivative financial instruments are accounted for as cash flow hedges. They 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, 2001, the Company would have received $4.7 million to terminate these options.

At September 30, 2001, the Company had long (purchased) futures contracts covering 15.9 Bcf of gas extending through 2003 at a weighted average contract price of $4.14 per Mcf. These derivative financial instruments are accounted for as fair value hedges. They are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with commercial and industrial customers. The Company would have had to pay $19.5 million to terminate these futures contracts at September 30, 2001.

At September 30, 2001, the Company had short (sold) futures contracts covering 2.7 Bcf of gas extending through 2003 at a weighted average contract price of $4.39 per Mcf. These derivative financial instruments are accounted for as fair value hedges. They are used by the Company's Energy Marketing segment and All Other category to hedge against falling prices, a risk to which they are exposed on their gas storage inventory and fixed price gas purchase commitments. The Company would have received $4.2 million to terminate these futures contracts at September 30, 2001.

The Company uses an interest rate swap to eliminate interest rate fluctuations on certain variable rate debt. Under the terms of the interest rate swap, which extends until 2002, the Company pays a fixed rate of 8.31% and receives a floating rate of six month Prague Interbank Offered Rate (PRIBOR). The interest rate swap is accounted for as a cash flow hedge. At September 30, 2001, the Company would have had to pay $0.6 million to terminate the interest rate swap.

The Company may be exposed to credit risk on some of its derivative financial instruments. 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, 2001, the Company's credit risk amounted to $36.4 million of net fair value that was owed to the Company for its price swap agreements, no cost collars and puts. There are five counterparties that comprise this credit risk, with the minimum and maximum credit risk from any of the counterparties being 9% and 45%, respectively of the total fair value at September 30, 2001. One of the counterparties, Enron, representing 29% of the total fair value at September 30, 2001, filed for bankruptcy protection subsequent to September 30, 2001. The bankruptcy filing effectively terminated the natural gas and crude oil price swap agreements as well as the crude oil no cost collars that the Company had entered into with Enron. The natural gas price swap agreements that were terminated covered 8.7 Bcf of production at a weighted average fixed rate of $4.19 per Mcf through the end of 2002. The crude oil price swap agreements that were terminated covered 645,000 bbls of production in 2002 at a weighted average fixed rate of $19.13 per bbl and 135,000 bbls of production in 2003 at a weighted average fixed rate of $19.10 per bbl. The crude oil no cost collars covered 80,000 bbls of production in 2002 at a weighted average ceiling price of $28.10 per bbl and a weighted average floor price of $21.00 per bbl. The Company replaced the Enron natural gas price swap agreements with natural gas no cost collars with another counterparty. The new natural gas no cost collars cover 7.5 Bcf of production in 2002 at a weighted average ceiling price of $4.21 per Mcf and a weighted average floor price of $2.15 per Mcf. In the first quarter of 2002, the Company expects to establish a reserve for up to a maximum amount of $10.7 million for what Enron owed the Company at the time of the termination of the derivative financial instruments (December 3, 2001). In accordance with SFAS 133, the amount of Accumulated Other Comprehensive Income associated with these cash flow hedges will be reclassified to the Consolidated Statement of Income when the hedged physical transactions occur, the majority of which will occur in 2002, as disclosed above.

NOTE G Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan) that covers substantially all 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. 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 Company is fully recovering its net periodic pension and post-retirement benefit costs 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 by their actuary under applicable accounting principles is recorded as either a regulatory asset or liability, as appropriate. Pension and post-retirement benefit costs reflect the amount recovered from customers in rates during the year. Under the NYPSC's policies, the Company segregates the amount of such costs collected in rates, but not yet contributed to the Retirement and Post-Retirement Plans, into a regulatory liability account. This liability accrues interest at the NYPSC-mandated interest rate, and this interest cost is included in pension and post-retirement benefit costs. For purposes of disclosure, the liability also remains in the disclosed pension and post-retirement benefit liability amount because it has not yet been contributed.

Retirement Plan

Reconciliations of the Benefit Obligation, Retirement Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions are as follows:

Year Ended September 30 (Thousands)	2001	2000	1999
Change in Benefit Obligation			
Benefit Obligation at Beginning of Period	$535,894	$538,796	$532,250
Service Cost	11,550	11,692	12,676
Interest Cost	39,061	37,954	36,299
Amendments	2,343	—	1,691
Actuarial (Gain) Loss	25,358	(20,216)	(13,598)
Benefits Paid	(34,160)	(32,332)	(30,522)
Benefit Obligation at End of Period	$580,046	$535,894	$538,796
Change in Plan Assets			
Fair Value of Assets at Beginning of Period	$569,936	$537,958	$509,393
Actual Return on Plan Assets	(19,248)	36,584	47,888
Employer Contribution	20,097	27,726	11,199
Benefits Paid	(34,160)	(32,332)	(30,522)
Fair Value of Assets at End of Period	$536,625	$569,936	$537,958
Reconciliation of Funded Status			
Funded Status	$(43,421)	$34,042	$(838)
Unrecognized Net Actuarial Gain	23,222	(62,008)	(45,853)
Unrecognized Transition Asset	(7,432)	(11,148)	(14,864)
Unrecognized Prior Service Cost	12,236	10,943	12,048
Accrued Benefit Cost	$(15,395)	$(28,171)	$(49,507)

	2001	2000	1999
Weighted Average Assumptions as of September 30			
Discount Rate	**7.25%**	7.50%	7.25%
Expected Return on Plan Assets	**8.50%**	8.50%	8.50%
Rate of Compensation Increase	**5.00%**	5.00%	5.00%
Year Ended September 30 (Thousands)			
Components of Net Periodic Benefit Cost			
Service Cost	**$11,550**	$11,692	$12,676
Interest Cost	**39,061**	37,954	36,299
Expected Return on Plan Assets	**(45,703)**	(41,077)	(38,158)
Amortization of Prior Service Cost	**1,050**	1,106	1,012
Amortization of Transition Amount	**(3,716)**	(3,716)	(3,716)
Recognition of Actuarial (Gain) or Loss	**(2,256)**	60	2,833
Early Retirement Window	**7,337**	—	7,032
Net Amortization and Deferral for Regulatory Purposes	**4,787**	206	2,721
Net Periodic Benefit Cost	**$12,110**	$6,225	$20,699

The effect of the discount rate change in 2001 was to increase the Benefit Obligation by $15.6 million as of the end of the period. The effect of the discount rate change in 2000 was to decrease the Benefit Obligation as of the end of the period by $15.3 million. A reduction in the salary increase assumption decreased the Benefit Obligation in 2001 by $1.5 million as of the end of the period. In 2000, there was no change in the salary increase assumption.

Other Post-Retirement Benefits

Reconciliations of the Benefit Obligation, Post-Retirement Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions are as follows:

Year Ended September 30 (Thousands)	2001	2000	1999
Change in Benefit Obligation			
Benefit Obligation at Beginning of Period	**$266,460**	$255,615	$256,983
Service Cost	**4,234**	4,156	4,493
Interest Cost	**19,557**	18,142	17,635
Plan Participants' Contributions	**524**	414	673
Amendments	**33**	—	—
Actuarial (Gain) Loss	**26,661**	(355)	(13,542)
Benefits Paid	**(12,921)**	(11,512)	(10,627)
Benefit Obligation at End of Period	**$304,548**	$266,460	$255,615
Change in Plan Assets			
Fair Value of Assets at Beginning of Period	**$176,357**	$149,884	$122,870
Actual Return on Plan Assets	**(19,685)**	18,527	17,345
Employer Contribution	**17,684**	19,044	19,623
Plan Participants' Contributions	**524**	414	673
Benefits Paid	**(12,921)**	(11,512)	(10,627)
Fair Value of Assets at End of Period	**$161,959**	$176,357	$149,884
Reconciliation of Funded Status			
Funded Status	**$(142,589)**	$(90,103)	$(105,731)
Unrecognized Net Actuarial (Gain) Loss	**52,832**	(8,676)	(2,396)
Unrecognized Transition Obligation	**85,526**	92,653	99,780
Unrecognized Prior Service Cost	**33**	—	—
Accrued Benefit Cost	**$(4,198)**	$(6,126)	$(8,347)

	2001	2000	1999
Weighted Average Assumptions as of September 30			
Discount Rate	**7.25%**	7.50%	7.25%
Expected Return on Plan Assets	**8.50%**	8.50%	8.50%
Rate of Compensation Increase	**5.00%**	5.00%	5.00%
Year Ended September 30 (Thousands)			
Components of Net Periodic Benefit Cost			
Service Cost	**$4,234**	$4,156	$4,493
Interest Cost	**19,557**	18,142	17,635
Expected Return on Plan Assets	**(14,787)**	(12,574)	(10,134)
Amortization of Transition Obligation	**7,127**	7,127	7,127
Amortization of (Gain) Loss	**(374)**	(24)	1,304
Net Amortization and Deferral for Regulatory Purposes	**4,075**	7,269	1,774
Net Periodic Benefit Cost	**$19,832**	$24,096	$22,199

The effect of the discount rate change in 2001 was to increase the Benefit Obligation by $9.8 million. The effect of the discount rate change in 2000 was to decrease the Benefit Obligation by $8.9 million.

The health care trend assumptions were changed in 2000 to better reflect anticipated future experience. The effect of the changed medical care, prescription drug and Medicare Part B assumptions was to increase the Accumulated Postretirement Benefit Obligation by $13.7 million. In 2001, there was no change in these assumptions.

The annual rate of increase in the per capita cost of covered medical care benefits was assumed to be 8.0% for 1999, 10.0% for 2000, 9.0% for 2001 and gradually decline to 5.5% by the year 2005 and remain level thereafter. The annual rate of increase for medical care benefits provided by healthcare maintenance organizations was assumed to be 7.0% in 1999, 10.0% in 2000, 9.0% in 2001 and gradually decline to 5.5% by the year 2005 and remain level thereafter. The annual rate of increase in the per capita cost of covered prescription drug benefits was assumed to be 8.0% for 1999, 15.0% for 2000, 13.0% for 2001 and gradually decline to 5.5% by the year 2005 and remain level thereafter. The annual rate of increase in the per capita Medicare Part B Reimbursement was assumed to be 8.0% for 1999, 10.0% for 2000, 9.0% for 2001 and gradually decline to 5.5% by the year 2005 and remain level thereafter.

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 Benefit Obligation as of October 1, 2001 would be increased by $43.1 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2001 by $3.8 million. If the health care cost trend rates were decreased by 1% in each year, the Benefit Obligation as of October 1, 2001 would be decreased by $35.4 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 2001 by $3.0 million.

NOTE H Commitments and Contingencies

Environmental Matters

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

It is the Company's policy to accrue estimated environmental clean-up costs (investigation and remediation) when such amounts can reasonably be estimated and it is probable that the Company will be required to incur such costs. The Company has estimated its remaining clean-up costs related to the sites described below in paragraphs (i) and (ii) will be in the range of $5.4 million to $6.4 million. The minimum estimated liability of $5.4 million has been recorded on the Consolidated Balance Sheet at September 30, 2001. Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, adverse changes in environmental regulations, new information or other factors could impact the Company.

(i) Former Manufactured Gas Plant Sites

The Company has incurred or is incurring clean-up costs at four former manufactured gas plant sites in New York and Pennsylvania. Remediation is substantially complete at a site where the Company has been designated by the New York Department of Environmental Conservation (DEC) as a potentially responsible party (PRP). The Company is engaged in litigation regarding that site with the DEC and the party who bought the site from the Company's predecessor. At a second site, remediation is in progress. At a third site, the Company is negotiating with the DEC for clean-up under a voluntary program under which costs are expected to approximate $1.4 million. The fourth site, which allegedly contains, among other things, manufactured gas plant waste, is in the investigation stage.

(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 final payments pending. At a second waste disposal site, settlement was reached in the amount of $5.5 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, has entered into contractual commitments in the ordinary course of business, including commitments to purchase capacity on nonaffiliated pipelines to meet customer gas supply needs. The majority of these contracts (representing 88% of contracted demand capacity) expire within the next five years. Costs incurred under these contracts are purchased gas costs, 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 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 I Business Segment Information

The Company has six reportable segments: Utility, Pipeline and Storage, Exploration and Production, International, Energy Marketing and Timber. The breakdown of the Company's 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 Pennsylvania Public Utility Commission (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 by the Federal Energy Regulatory Commission (FERC) and are carried out by Supply Corporation and SIP. 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. SIP, although not regulated itself by the FERC, holds a one-third partnership interest in the Independence Pipeline Company, whose rates, services and other matters are or are anticipated to be regulated by the FERC.

The Exploration and Production segment, through Seneca, is engaged in exploration for, and development and purchase of, natural gas and oil reserves in the Gulf Coast region of Texas and Louisiana, in California, in Wyoming, in the Appalachian region of the United States and in the provinces of Manitoba, Alberta and Saskatchewan in Canada. Seneca's production is, for the most part, sold to purchasers located in the vicinity of its wells.

The International segment's operations are carried out by Horizon. Horizon engages in foreign energy projects through the investment of its indirect subsidiaries as the sole or partial owner of various business entities. Horizon's current emphasis is the Czech Republic, where, through its subsidiaries, it owns majority interests in companies having district heating and power generation plants in the northern Bohemia region.

The Energy Marketing segment is comprised of NFR's operations. NFR is engaged in the retail marketing of natural gas and the performance of energy management services for industrial, commercial, public authority and residential end-users located in the northeastern United States.

The Timber segment's operations are carried out by the Northeast division of Seneca and by Highland. This segment has timber holdings in the northeastern United States and several sawmills and kilns in Pennsylvania.

The data presented in the tables below reflect the reportable segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A - Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. Expenditures for long-lived assets include additions to property, plant and equipment and equity investments in corporations (stock acquisitions) or partnerships, net of any cash acquired. 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.

Year Ended September 30, 2001 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	**$1,214,614**	**$81,057**	**$398,344**	**$97,910**	**$259,206**	**$42,091**	**$2,093,222**	**$7,130**	**$ —**	**$2,100,352**
Intersegment Revenues	**20,033**	**90,034**	**—**	**—**	**—**	**—**	**110,067**	**11,192**	**(121,259)**	**—**
Interest Expense	**27,489**	**12,131**	**56,291**	**9,966**	**1,649**	**3,830**	**111,356**	**692**	**(4,903)**	**107,145**
Depreciation, Depletion and Amortization	**36,607**	**23,746**	**98,408**	**12,634**	**212**	**3,186**	**174,793**	**119**	**2**	**174,914**
Income Tax Expense	**42,985**	**29,091**	**(36,075)**	**253**	**(1,660)**	**4,566**	**39,160**	**(2,281)**	**227**	**37,106**
Significant Non-cash Item: Impairment of Oil and Gas Producing Properties	**—**	**—**	**180,781**	**—**	**—**	**—**	**180,781**	**—**	**—**	**180,781**
Segment Profit (Loss): Net Income	**60,707**	**40,377**	**(32,284)**	**(3,042)**	**(3,432)**	**7,715**	**70,041**	**(4,277)**	**(265)**	**65,499**
Expenditures for Additions to Long-Lived Assets	**42,374**	**25,978**	**296,419**	**15,585**	**116**	**3,694**	**384,166**	**937**	**—**	**385,103**
At September 30, 2001 (Thousands)										
Segment Assets	**$1,284,189**	**$549,991**	**$1,194,393**	**$206,361**	**$68,513**	**$113,294**	**$3,416,741**	**$26,858**	**$1,967**	**$3,445,566**

Year Ended September 30, 2000 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$827,231	$81,434	$237,845	$104,736	$133,929	$39,172	$1,424,347	$930	$ —	$1,425,277
Intersegment Revenues	19,228	88,225	225	—	—	—	107,678	4,415	(112,093)	—
Interest Expense	31,655	13,311	42,034	12,353	774	4,750	104,877	262	(5,054)	100,085
Depreciation, Depletion and Amortization	35,842	23,379	69,583	11,110	209	1,948	142,071	97	2	142,170
Income Tax Expense	38,362	22,172	19,413	(1,783)	(4,372)	3,816	77,608	(205)	(335)	77,068
Segment Profit (Loss): Net Income	57,662	31,614	34,877	3,282	(7,790)	6,133	125,778	(371)	1,800	127,207
Expenditures for Additions to Long-Lived Assets	55,799	35,806 (1)	280,049	9,767	89	13,542	395,052	3,725	—	398,777
At September 30, 2000 (Thousands)										
Segment Assets	$1,233,639	$552,059	$1,088,066	$202,622	$47,121	$107,402	$3,230,909	$21,930	$(1,808)	$3,251,031

(1) Amount includes $1.2 million in a stock-for-asset swap.

Year Ended September 30, 1999 (Thousands)	Utility	Pipeline and Storage	Exploration and Production	International	Energy Marketing	Timber	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$801,053	$82,994	$140,212	$107,045	$99,088	$31,117	$1,261,509	$1,765	$ —	$1,263,274
Intersegment Revenues	6,302	85,789	6,782	—	—	—	98,873	—	(98,873)	—
Interest Expense	29,659	13,147	34,409	11,451	234	2,208	91,108	100	(3,510)	87,698
Depreciation, Depletion and Amortization	34,215	22,690	55,750	10,473	165	1,476	124,769	7	2	124,778
Income Tax Expense	34,741	22,439	2,992	15	1,138	2,788	64,113	55	661	64,829
Segment Profit (Loss): Net Income	56,875	39,765	7,127	2,276	2,054	4,769	112,866	(162)	2,333	115,037
Expenditures for Additions to Long-Lived Assets	46,974	34,873	97,586	33,412	302	52,314	265,461	66	—	265,527
At September 30, 1999 (Thousands)										
Segment Assets	$1,178,185	$542,962	$727,557	$255,042	$18,676	$98,830	$2,821,252	$7,351	$13,983	$2,842,586

GEOGRAPHIC INFORMATION

For the Year Ended September 30 (Thousands)	2001	2000	1999
Revenues from External Customers (1):			
United States	**$1,928,474**	$1,292,190	$1,156,229
Czech Republic	**97,910**	104,736	107,045
Canada	**73,968**	28,351	—
	$2,100,352	$1,425,277	$1,263,274
At September 30 (Thousands)			
Long-Lived Assets:			
United States	**$2,645,764**	$2,488,180	$2,369,840
Czech Republic	**187,961**	183,274	215,457
Canada	**257,939**	248,937	—
	$3,091,664	$2,920,391	$2,585,297

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

NOTE J Stock Acquisitions

In June 2001, the Company acquired the outstanding shares of Player Petroleum Corporation (Player), an oil and gas exploration and development company, with operations based primarily in the Province of Alberta, Canada. The cost of acquiring the outstanding shares of Player was approximately $90.6 million and the acquisition was accounted for in accordance with the purchase method. Player'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 30, 2001.

In June 2000, the Company acquired the outstanding shares of Tri Link Resources, Ltd. (Tri Link) a Calgary, Alberta-based oil and gas exploration and production company. The cost of acquiring the outstanding shares of Tri Link was approximately $123.8 million and the acquisition was accounted for in accordance with the purchase method. Tri Link'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 15, 2000.

Details of the stock acquisitions made by the Company during 2001 and 2000 are as follows:

Year Ended September 30 (Millions)	2001	2000
Assets acquired	**$175.1**	$259.9
Liabilities assumed	**(84.5)**	(136.1)
Cash paid	**$90.6**	$123.8

Total goodwill outstanding amounted to $11.1 million and $12.1 million at September 30, 2001 and 2000, respectively. This goodwill is recorded in Other Assets and is being amortized over a maximum period of twenty years.

NOTE K 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 Statement of Income. Those per common share amounts are based on the weighted average number of shares outstanding for the entire fiscal year. Because of the seasonal nature of the Company's heating business, there are substantial variations in operations reported on a quarterly basis.

Quarter Ended	Operating Revenues	Operating Income (Loss)	Net Income (Loss) Available for Common Stock	Earnings (Loss) Per Common Share Basic	Earnings (Loss) Per Common Share Diluted
2001	*(Thousands, except per common share amounts)*				
12/31/2000	**$559,504**	**$ 75,121**	**$ 52,984**[1]	**$ 0.67**	**$ 0.66**
3/31/2001	**$879,869**	**$103,572**	**$ 75,275**[2]	**$ 0.95**	**$ 0.94**
6/30/2001	**$406,494**	**$ 59,603**	**$ 36,618**	**$ 0.46**	**$ 0.45**
9/30/2001	**$254,485**	**$ (79,566)**	**$(99,378)**[3]	**$(1.25)**	**$(1.24)**
2000	*(Thousands, except per common share amounts)*				
12/31/1999	$377,031	$70,237	$44,868	$0.58	$0.57
3/31/2000	$517,767	$91,074	$71,051	$0.91	$0.90
6/30/2000	$281,201	$30,043	$ 9,070[4]	$0.12	$0.11
9/30/2000	$249,278	$26,914	$ 2,218[5]	$0.03	$0.03

(1) Includes expense of $7.5 million related to Stock Appreciation Rights (SARs), expense of $1.2 million related to early retirement offers and income of $2.6 million related to the termination of a long-term transportation contract.
(2) Includes income of $9.7 million related to SARs and expense of $4.2 million related to early retirement offers.
(3) Includes income of $5.3 million related to SARs and expense of $104.0 million related to the impairment of oil and gas assets.
(4) Includes expense of $14.2 million related to mark-to-market and other revenue adjustments related to derivative financial instruments and expense of $3.5 million related to SARs.
(5) Includes expense of $6.6 million related to SARs, expense of $3.7 million for adjustments related to the New York rate settlement, expense of $1.6 million related to the recording of a loss contingency on fixed price sales contracts and income of $3.9 million related to mark-to-market and other revenue adjustments related to derivative financial instruments.

NOTE L Market for Common Stock and Related Shareholder Matters (unaudited)

At September 30, 2001, there were 20,345 holders of National Fuel Gas 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. The quarterly price ranges and quarterly dividends declared for the fiscal years ended September 30, 2001 and 2000, are shown below:

Quarter Ended	Price Range High	Price Range Low	Dividends Declared
2001			
12/31/2000	**$32.25**	**$25.57**	**$.240**
3/31/2001	**$31.60**	**$25.01**	**$.240**
6/30/2001	**$28.99**	**$25.90**	**$.2525**
9/30/2001	**$26.38**	**$21.96**	**$.2525**
2000			
12/31/1999	$26.47	$23.00	$.2325
3/31/2000	$23.38	$19.69	$.2325
6/30/2000	$25.97	$21.57	$.240
9/30/2000	$29.41	$24.07	$.240

NOTE M Supplementary Information for Oil and Gas Producing Activities

The following supplementary information is presented in accordance with SFAS No. 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 (Thousands)	2001	2000
Proved Properties	$1,586,889	$1,218,871
Unproved Properties	152,326	152,360
	1,739,215	1,371,231
Less - Accumulated Depreciation, Depletion and Amortization	675,256	390,267
	$1,063,959	$980,964

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, 2001:

	Total as of September 30,	Year Costs Incurred			
(Thousands)	2001	2001	2000	1999	Prior
Acquisition Costs	$152,326	$35,272	$72,797	$4,675	$39,582

COSTS INCURRED IN OIL AND GAS PROPERTY ACQUISITION, EXPLORATION AND DEVELOPMENT ACTIVITIES

Year Ended September 30 (Thousands)	2001	2000	1999
United States			
Property Acquisition Costs:			
Proved	$1,713	$2,848	$2,798
Unproved	15,296	19,066	11,530
Exploration Costs	42,338	50,163	52,141
Development Costs	88,987	72,039	30,985
	148,334	144,116	97,454
Canada			
Property Acquisition Costs:			
Proved	115,643	159,268	—
Unproved	2,612	77,198	—
Exploration Costs	8,523	573	—
Development Costs	36,554	11,013	—
	163,332	248,052	—
Total			
Property Acquisition Costs: (1)			
Proved	117,356	162,116	2,798
Unproved	17,908	96,264	11,530
Exploration Costs	50,861	50,736	52,141
Development Costs	125,541	83,052	30,985
	$311,666	$392,168	$97,454

(1) Total proved and unproved property acquisition costs for 2001 of $135.3 million include $107.6 million related to the Player acquisition. Total proved and unproved property acquisition costs for 2000 of $258.4 million include $236.5 million related to the Tri Link acquisition.

RESULTS OF OPERATIONS FOR PRODUCING ACTIVITIES

Year Ended September 30 (Thousands, Except Per Mcfe Amounts)	2001	2000	1999
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $4, $237 and $6,365, respectively)	**$216,729**	$137,336	$81,734
Oil, Condensate and Other Liquids	**121,973**	107,645	51,592
Total Operating Revenues (1)	**338,702**	244,981	133,326
Production/Lifting Costs	**37,068**	33,979	28,119
Depreciation, Depletion and Amortization ($1.13, $0.97 and $0.89 per Mcfe of production)	**76,686**	64,624	54,439
Income Tax Expense	**83,649**	52,656	16,255
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	**141,299**	93,722	34,513
Canada			
Operating Revenues:			
Natural Gas	**4,379**	485	—
Oil, Condensate and Other Liquids	**74,349**	26,320	—
Total Operating Revenues (1)	**78,728**	26,805	—
Production/Lifting Costs	**27,089**	7,858	—
Depreciation, Depletion and Amortization ($0.93, $0.77 and $ - per Mcfe of production)	**18,719**	4,321	—
Impairment of Oil and Gas Producing Properties (2)	**180,781**	—	—
Income Tax Expense (Benefit)	**(63,795)**	6,121	—
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	**(84,066)**	8,505	—
Total			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $4, $237 and $6,365, respectively)	**221,108**	137,821	81,734
Oil, Condensate and Other Liquids	**196,322**	133,965	51,592
Total Operating Revenues (1)	**417,430**	271,786	133,326
Production/Lifting Costs	**64,157**	41,837	28,119
Depreciation, Depletion and Amortization ($1.08, $0.95 and $0.89 per Mcfe of production)	**95,405**	68,945	54,439
Impairment of Oil and Gas Producing Properties (2)	**180,781**	—	—
Income Tax Expense	**19,854**	58,777	16,255
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	**$57,233**	$102,227	$34,513

(1)Exclusive of hedging gains and losses. See further discussion in Note F - Financial Instruments.
(2)See discussion of impairment in Note A - Summary of Significant Accounting Policies.

Reserve Quantity Information (unaudited)

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

	Gas MMcf			Oil Mbbl		
	U.S.	Canada	Total	U.S.	Canada	Total
Proved Developed and Undeveloped Reserves:						
September 30, 1998	325,065	—	325,065	66,591	—	66,591
Extensions and Discoveries	46,423	—	46,423	3,716	—	3,716
Revisions of Previous Estimates	(13,091)	—	(13,091)	9,808	—	9,808
Production	(37,166)	—	(37,166)	(4,016)	—	(4,016)
Sales of Minerals in Place	(439)	—	(439)	(280)	—	(280)
Purchases of Minerals in Place and Other	—	—	—	—	—	—
September 30, 1999	320,792	—	320,792	75,819	—	75,819
Extensions and Discoveries	34,641	—	34,641	2,167	1,765	3,932
Revisions of Previous Estimates	(8,001)	—	(8,001)	4,000	—	4,000
Production	(41,478)	(192)	(41,670)	(4,248)	(899)	(5,147)
Sales of Minerals in Place	(7,444)	—	(7,444)	(227)	—	(227)
Purchases of Minerals in Place and Other	—	3,349	3,349	—	41,320	41,320
September 30, 2000	**298,510**	**3,157**	**301,667**	**77,511**	**42,186**	**119,697**
Extensions and Discoveries	**35,960**	**15,681**	**51,641**	**924**	**3,625**	**4,549**
Revisions of Previous Estimates	**(22,813)**	**(34)**	**(22,847)**	**1,737**	**(5,396)**	**(3,659)**
Production	**(39,188)**	**(1,816)**	**(41,004)**	**(4,796)**	**(3,061)**	**(7,857)**
Sales of Minerals in Place	**(6,066)**	**(280)**	**(6,346)**	**(685)**	**(80)**	**(765)**
Purchases of Minerals in Place and Other	**410**	**38,859**	**39,269**	**104**	**3,259**	**3,363**
September 30, 2001	**266,813**	**55,567**	**322,380**	**74,795**	**40,533**	**115,328**
Proved Developed Reserves:						
September 30, 1998	230,508	—	230,508	48,081	—	48,081
September 30, 1999	222,929	—	222,929	57,333	—	57,333
September 30, 2000	227,250	3,157	230,407	66,074	35,130	101,204
September 30, 2001	**213,792**	**53,463**	**267,255**	**50,640**	**33,676**	**84,316**

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 the widely fluctuating political and economic conditions of today's world.

The standardized measure is intended instead to provide a somewhat better 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 (Thousands)	**2001**	**2000**	**1999**
United States			
Future Cash Inflows	**$2,127,601**	$3,886,499	$2,402,308
Less:			
Future Production Costs	**602,479**	600,243	560,459
Future Development Costs	**121,240**	179,565	185,617
Future Income Tax Expense at Applicable Statutory Rate	**376,667**	1,006,366	477,205
Future Net Cash Flows	**1,027,215**	2,100,325	1,179,027
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**421,865**	859,950	471,768
Standardized Measure of Discounted Future Net Cash Flows	**605,350**	1,240,375	707,259
Canada			
Future Cash Inflows	**890,381**	1,083,598	—
Less:			
Future Production Costs	**533,848**	277,067	—
Future Development Costs	**19,608**	21,399	—
Future Income Tax Expense at Applicable Statutory Rate	**76,191**	286,148	—
Future Net Cash Flows	**260,734**	498,984	—
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**79,295**	221,227	—
Standardized Measure of Discounted Future Net Cash Flows	**181,439**	277,757	—
Total			
Future Cash Inflows	**3,017,982**	4,970,097	2,402,308
Less:			
Future Production Costs	**1,136,327**	877,310	560,459
Future Development Costs	**140,848**	200,964	185,617
Future Income Tax Expense at Applicable Statutory Rate	**452,858**	1,292,514	477,205
Future Net Cash Flows	**1,287,949**	2,599,309	1,179,027
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	**501,160**	1,081,177	471,768
Standardized Measure of Discounted Future Net Cash Flows	**$786,789**	$1,518,132	$707,259

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

Year Ended September 30 (Thousands)	2001	2000	1999
United States			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	**$1,240,375**	$707,259	$466,771
Sales, Net of Production Costs	**(301,634)**	(211,002)	(53,615)
Net Changes in Prices, Net of Production Costs	**(921,719)**	795,408	317,356
Purchases of Minerals in Place	**1,191**	—	—
Sales of Minerals in Place	**(17,552)**	(11,914)	(2,706)
Extensions and Discoveries	**52,062**	186,818	122,894
Changes in Estimated Future Development Costs	**(3,157)**	(82,270)	(97,082)
Previously Estimated Development Costs Incurred	**61,482**	88,322	72,349
Net Change in Income Taxes at Applicable Statutory Rate	**363,425**	(292,371)	(232,085)
Revisions of Previous Quantity Estimates	**(29,841)**	20,736	40,964
Accretion of Discount and Other	**160,718**	39,389	72,413
Standardized Measure of Discounted Future Net Cash Flows at End of Year	**605,350**	1,240,375	707,259
Canada			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	**277,757**	—	—
Sales, Net of Production Costs	**(51,638)**	(18,948)	—
Net Changes in Prices, Net of Production Costs	**(161,461)**	—	—
Purchases of Minerals in Place	**30,575**	424,072	—
Sales of Minerals in Place	**(761)**	—	—
Extensions and Discoveries	**39,752**	2,979	—
Changes in Estimated Future Development Costs	**(31,009)**	—	—
Previously Estimated Development Costs Incurred	**12,176**	—	—
Net Change in Income Taxes at Applicable Statutory Rate	**73,865**	(150,057)	—
Revisions of Previous Quantity Estimates	**(64,368)**	—	—
Accretion of Discount and Other	**56,551**	19,711	—
Standardized Measure of Discounted Future Net Cash Flows at End of Year	**181,439**	277,757	—
Total			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	**1,518,132**	707,259	466,771
Sales, Net of Production Costs	**(353,272)**	(229,950)	(53,615)
Net Changes in Prices, Net of Production Costs	**(1,083,180)**	795,408	317,356
Purchases of Minerals in Place	**31,766**	424,072	—
Sales of Minerals in Place	**(18,313)**	(11,914)	(2,706)
Extensions and Discoveries	**91,814**	189,797	122,894
Changes in Estimated Future Development Costs	**(34,166)**	(82,270)	(97,082)
Previously Estimated Development Costs Incurred	**73,658**	88,322	72,349
Net Change in Income Taxes at Applicable Statutory Rate	**437,290**	(442,428)	(232,085)
Revisions of Previous Quantity Estimates	**(94,209)**	20,736	40,964
Accretion of Discount and Other	**217,269**	59,100	72,413
Standardized Measure of Discounted Future Net Cash Flows at End of Year	**$786,789**	$1,518,132	$707,259

Schedule II

VALUATION AND QUALIFYING ACCOUNTS

(Thousands) 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
Year Ended September 30, 2001					
Reserve for Doubtful Accounts	**$12,013**	**$17,445**	**$ —**	**$10,937**	**$18,521**
Year Ended September 30, 2000					
Reserve for Doubtful Accounts	$7,842	$15,177	$ —	$11,006	$12,013
Year Ended September 30, 1999					
Reserve for Doubtful Accounts	$6,232	$15,337	$1	$13,728	$ 7,842

(1) Represents opening balance sheet reserve plus exchange rate impact of translating the Czech koruna to the U.S. dollar for Horizon.
(2) Amounts represent net accounts receivable written-off.

ITEM 9 Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

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 21, 2002 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2001. The information concerning directors is set forth in the definitive Proxy Statement under the captions entitled "Nominees for Election as Directors for Three-Year Terms to Expire 2004," "Directors Whose Terms Expire in 2003," "Directors Whose Terms Expire in 2002," 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.

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 21, 2002 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2001. The information concerning executive compensation is set forth in the definitive Proxy Statement under the captions "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

(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 21, 2002 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2001. The information concerning security ownership of certain beneficial owners is set forth in the definitive Proxy Statement under the caption "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 21, 2002 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2001. The information concerning security ownership of management is set forth in the definitive Proxy Statement under the caption "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 21, 2002 Annual Meeting of Shareholders will be filed with the SEC not later than 120 days after September 30, 2001. The information regarding certain relationships and related transactions is set forth in the definitive Proxy Statement under the caption "Compensation Committee Interlocks and Insider Participation" and is incorporated herein by reference.

Part IV

ITEM 14 Exhibits, Financial Statement Schedules, and Reports on Form 8-K

(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 statements 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.

Exhibit Number — **Description of Exhibits**

(a)3. 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)

3(ii) By-Laws:

3.1 National Fuel Gas Company By-Laws as amended on September 20, 2001

(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)
- Tenth Supplemental Indenture, dated as of February 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(a), Form 8-K dated February 14, 1992 in File No. 1-3880)
- 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)
- Officer's 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)

(10) Material Contracts:

(iii) Compensatory plans for officers:

- Retirement and Consulting Agreement, dated September 5, 2001, between the Company and Bernard J. Kennedy (Exhibit 10(iii)(a), Form 8-K dated September 19, 2001 in File No. 1-3880)
- Pension Settlement Agreement, dated September 5, 2001, between the Company and Bernard J. Kennedy (Exhibit 10(iii)(b), Form 8-K dated September 19, 2001 in File No. 1-3880)
- Employment Agreement, dated September 17, 1981, between the Company and Bernard J. Kennedy (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1994 in File No. 1-3880)
- Tenth Amendment to Employment Agreement between the Company and Bernard J. Kennedy, effective September 1, 1999 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Agreement, dated August 1, 1986, between the Company and Joseph P. Pawlowski (Exhibit 10.1, Form 10-K for fiscal year ended September 30,1997 in File No. 1-3880)
- Agreement, dated August 1, 1986, between the Company and Gerald T. Wehrlin (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1997, in File No. 1-3880)
- Form of Employment Continuation and Noncompetition Agreements, dated as of December 11, 1998, between the Company and each of Philip C. Ackerman, Walter E. DeForest, Joseph P. Pawlowski, Dennis J. Seeley, David F. Smith and Gerald T. Wehrlin (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 1999 in File No. 1-3880)
- Severance Agreement, Release and Waiver dated March 27, 2000, between National Fuel Gas Supply Corporation and Richard Hare (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2000)
- Form of Employment Continuation and Noncompetition Agreement, dated as of December 11, 1998, between the Company 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 1983 Incentive Stock Option Plan, as amended and restated through February 18, 1993 (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880)
- National Fuel Gas Company 1984 Stock Plan, as amended and restated through February 18, 1993 (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 1993 in File No. 1-3880)
- Amendment to the National Fuel Gas Company 1984 Stock Plan, dated December 11, 1996 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1996 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)

10.1 National Fuel Gas Company 1993 Award and Option Plan, amended through June 14, 2001

10.2 National Fuel Gas Company 1997 Award and Option Plan, amended through June 14, 2001

10.3 Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001

- 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 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996 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)
- 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)
- 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)
- Death Benefits Agreement, dated August 28, 1991, between the Company and Bernard J. Kennedy (Exhibit 10-TT, Form 10-K for fiscal year ended September 30, 1991 in File No. 1-3880)
- Amendment to Death Benefit Agreement of August 28, 1991, between the Company and Bernard J. Kennedy, dated March 15, 1994 (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1995 in File No. 1-3880)
- Amended and 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 Joseph P. Pawlowski (Exhibit 10.7, 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 Joseph P. Pawlowski, dated March 23, 1999 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Second Amended and Restated Split Dollar Insurance Agreement dated June 15, 1999, between the Company and Gerald T. Wehrlin (Exhibit 10.6, 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 Walter E. DeForest (Exhibit 10.7, 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 Walter E. DeForest, dated March 29, 1999 (Exhibit 10.8, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and Dennis J. Seeley (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Dennis J. Seeley, dated March 29, 1999 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Split Dollar Insurance and Death Benefit Agreement dated September 15, 1997, between the Company and Bruce H. Hale (Exhibit 10.11, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and Bruce H. Hale, dated March 29, 1999 (Exhibit 10.12, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999 in File No. 1-3880)
- National Fuel Gas Company 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)
- 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)

- 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, dated September 13, 2001 (Exhibit 10(iii)(c), Form 8-K dated September 19, 2001 in File No. 1-3880)
- Administrative Rules with Respect to at Risk Awards under the 1993 Award and Option Plan (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1996 in File No. 1-3880)
- Administrative Rules with Respect to at Risk Awards under the 1997 Award and Option Plan (Exhibit A, Definitive Proxy Statement, Schedule 14(A) filed January 14, 2000 in File No. 1-3880)
- Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated, effective December 10, 1998 (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 1998 in File No. 1-3880)
- Excerpts of Minutes from the National Fuel Gas Company Board of Directors Meeting of February 20, 1997 regarding the Retirement Benefits for Bernard J. Kennedy (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1997 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)

(12) Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 1997 through 2001

(21) Subsidiaries of the Registrant: See Item 1 of Part I of this Annual Report on Form 10-K

(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 National Fuel Exploration Corp.

23.3 Consent of Ralph E. Davis Associates, Inc. regarding Player Resources Ltd.

23.4 Consent of Independent Accountants

(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 National Fuel Exploration Corp.

99.3 Report of Ralph E. Davis Associates, Inc. regarding Player Resources Ltd.

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.

- *Incorporated herein by reference as indicated.*

(b) Reports on Form 8-K

A report on Form 8-K dated September 19, 2001 was filed on September 21, 2001, to report the election of Philip C. Ackerman as Chief Executive Officer, under Item 5, "Other Events." Related exhibits were reported under Item 7, "Financial Statements, Pro Forma Financial Information and Exhibits."

A report on Form 8-K dated September 7, 2001 was filed on September 7, 2001, to report information related to the Company's two-for-one stock split, under Item 5, "Other Events." A related exhibit was reported under Item 7, "Financial Statements, Pro Forma Financial Information and Exhibits."

A report on Form 8-K dated July 25, 2001 was filed on July 27, 2001, to report the release of revised earnings projections for fiscal year 2002 for the Company and its subsidiary, Seneca Resources Corporation, under Item 5, "Other Events." Related exhibits were reported under Item 7, "Financial Statements, Pro Forma Financial Information and Exhibits."

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/ B. J. Kennedy

B. J. Kennedy
Chairman of the Board
Date: December 13, 2001

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

SIGNATURE / TITLE

/s/ B. J. Kennedy

B. J. Kennedy
Chairman of the Board
Date: December 13, 2001

/s/ P. C. Ackerman

P. C. Ackerman
Chief Executive Officer, President, Principal Financial Officer and Director
Date: December 13, 2001

/s/ R. T. Brady

R. T. Brady
Director
Date: December 13, 2001

/s/ J. V. Glynn

J. V. Glynn
Director
Date: December 13, 2001

/s/ W. J. Hill

W. J. Hill
Director
Date: December 13, 2001

SIGNATURE / TITLE

/s/ B. S. Lee

B. S. Lee
Director
Date: December 13, 2001

/s/ E. T. Mann

E. T. Mann
Director
Date: December 13, 2001

/s/ G. L. Mazanec

G. L. Mazanec
Director
Date: December 13, 2001

/s/ J. F. Riordan

J. F. Riordan
Director
Date: December 13, 2001

/s/ J. P. Pawlowski

J. P. Pawlowski
Treasurer and Principal Accounting Officer
Date: December 13, 2001

Glossary

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.

BOPD Barrels of oil per day

Bubbling Fluidized Bed Boiler A boiler that is fueled by coal mixed with granulated limestone in a bed that is maintained in a mobile suspension by the upward flow of air.

Combined-Cycle Power Plant A power plant that produces electricity by use of a gas-fired turbine to turn an electric generator. Exhaust heat is used by a heat recovery steam generator, where steam is produced to turn a steam turbine, which then turns a second electric generator.

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.

Delubing The removal of additives by preheating before sintering.

Derivative A contract, as an option or futures contract, whose value depends on the value of the securities, commodities, etc. that form the basis of the contract.

Distributed Generation Any power generation technology (such as fuel cells, microturbines, engines, turbines, etc.) that provides electric power at a site closer to customers than a central generating station. A distributed generation unit can be connected directly to the end user, or to an electric utility's transmission or distribution system.

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.

Farm-Out An interest in an oil or gas lease which is granted to a third party by the lease holder.

FERC Federal Energy Regulatory Commission

Firm Transportation and/or Storage The transportation and/or storage service that a supplier of such service is obligated by contract to provide.

Gathering System The pipes, pumps, auxiliary tanks (in the case of oil), and other equipment used to move oil or gas from the well site to the main pipeline for eventual delivery to the refinery or consumer, as the case may be. In the case of gas, the gathering system includes the processing plant (if any) in which the gas is prepared for the market.

Geotechnical Engineering The application of scientific methods and engineering principles to the acquisition, interpretation and use of knowledge of materials of the earth's crust to the solution of engineering problems.

Gigajoule One billion joules. A "joule" is a unit of energy.

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

Hedging A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes.

Hub Location where pipelines intersect enabling the trading, transportation, storage, exchange and lending 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.

Kiln An oven, furnace, or heated enclosure used for processing a substance by burning, firing, or drying.

Kilowatt (kW) A unit of electrical power equal to one thousand watts.

Magnetic Flux Leakage Tool See **Pigging Operation**

Mbbl Thousand barrels

Mcf Thousand cubic feet

MDth Thousand dekatherms

Megawatt One million watts. A "watt" is a unit of electrical power.

Megawatt Hour A unit of electrical energy which equals one megawatt of power used for one hour.

Microturbine A small-scale gas turbine, typically producing less than 1,000 kilowatts (kW) of power. The technology employed by microturbines is the same as that of jet engines, using rotating power to drive electric generators that produce electricity.

MMcf Million cubic feet

MMcfe Million cubic feet equivalent (1 barrel of oil = 6 Mcf of gas)

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

NYPSC State of New York Public Service Commission

Open Access Transportation The transportation of natural gas by a pipeline or utility upon request.

PaPUC Pennsylvania Public Utility Commission

Pigging Operation The process of running a scraping device for cleaning and testing petroleum and natural gas pipelines. Pigging tools include: cleaning pigs, used to remove any internal debris; geometry pigs, used to identify dents and bends in the pipeline; and wall loss tools (magnetic flux leakage tool), used to identify corrosion and other defects.

Reserves Estimated volumes of oil, gas or other minerals that can be recovered from deposits in the earth with reasonable certainty.

Reserve-to-Production Ratio An estimate used to project the productive life of a field based upon the size of the field compared to the annual production capacity, expressed in years' supply.

Retrofit Upgrade or improvement in the performance of lighting accomplished by improving the electrical, optical, or thermal efficiency of lighting equipment and/or improving the utilization of light by improving rooms and buildings in which the light is provided.

Scale To measure.

Simple-Cycle Power Plant A power plant that produces electricity by use of a gas-fired turbine to turn an electric generator. Exhaust heat is released into the atmosphere.

Sintering The bonding of adjacent surfaces of (metal powder) particles by heating.

Spot Gas Purchases The purchase of natural gas on a short-term basis usually at a lower cost than long-term pipeline contracts.

Stranded Costs Costs associated with facilities or contracts that, because of restructuring, may not be directly recoverable from customers.

Tonne A metric ton; a unit of weight equivalent to 1,000 kilograms.

Transportation Gas The movement of gas for third parties through pipeline facilities for a fee.

Unbundled Service The separation of services, with rates charged that reflect the cost of the selected service.

Underground Storage The injection of large quantities of natural gas into underground rock formations for storage during periods of low market demand and withdrawal during periods of high market demand.

Veneer A thin surface layer of fine wood laid over a base of common material.

Weather Normalization A clause in utility rates which adjusts customer costs to reflect normal temperatures. If temperatures during the measured period are warmer than normal, customers receive a surcharge. If temperatures during the measured period are colder than normal, customers receive a credit.

Weighted Average Price A price computed by averaging together the cost of each unit.

Officers

National Fuel Gas Company

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

Joseph P. Pawlowski
Treasurer

Gerald T. Wehrlin
Controller

Anna Marie Cellino
Secretary

Officers of Principal Subsidiaries

National Fuel Gas Distribution Corporation

Philip C. Ackerman
*Chairman of the Board**

David F. Smith
President

Anna Marie Cellino
Senior Vice President and Secretary

Walter E. DeForest
Senior Vice President

Joseph P. Pawlowski
Senior Vice President and Treasurer

James D. Ramsdell
Senior Vice President

Dennis J. Seeley
Senior Vice President

Ronald J. Tanski
Senior Vice President and Controller

Carl M. Carlotti
Vice President

National Fuel Gas Supply Corporation

Philip C. Ackerman
*Chairman of the Board**

Dennis J. Seeley
President

Bruce H. Hale
Senior Vice President

John R. Pustulka
Senior Vice President

David F. Smith
Senior Vice President

Joseph P. Pawlowski
Treasurer and Secretary

Seneca Resources Corporation

Philip C. Ackerman
*Chairman of the Board**

James A. Beck
President

Barry L. McMahan
Senior Vice President

William M. Petmecky
Senior Vice President and Secretary

Don A. Brown
Vice President

Robert T. Evans
Vice President

Gil E. Klefstad
Vice President

John F. McKnight
Vice President

Emmett E. Wassell
Vice President

Thomas L. Atkins
Treasurer and Assistant Secretary

National Fuel Resources, Inc.

Gerald T. Wehrlin
President

Donna L. DeCarolis
Vice President

William M. Petmecky
Treasurer and Secretary

Highland Forest Resources, Inc.

James A. Beck
President

William M. Petmecky
Secretary

Thomas L. Atkins
Treasurer

Horizon Energy Development, Inc.

Philip C. Ackerman
President

Bruce H. Hale
Vice President

Gerald T. Wehrlin
Vice President

Ronald J. Tanski
Treasurer and Secretary

* *Effective January 3, 2002, Philip C. Ackerman became Chairman of the Board, He succeeded retired Chairman Bernard J. Kennedy.*

Directors

Philip C. Ackerman [6]
Chairman of the Board* of Directors of the Company, Chief Executive Officer since October 2001, and President since July 1999. Chairman of the Board* 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. Board member since 1995. Director of Acme Electric Corporation, Astronics Corporation, M&T Bank Corporation, M&T Bank and Seneca Foods Corporation.

James V. Glynn [1, 7]
Chairman since November 2001 of Maid of the Mist Corporation and former President from 1971 to November 2001. Board member since 1997. Director of M&T Bank Corporation, M&T Bank, and Chairman of Niagara University Board of Trustees.

William J. Hill [1, 5, 7]
Retired President of National Fuel Gas Distribution Corporation. Board member since 1995. Director of National Fuel Gas Distribution Corporation and Reed Manufacturing Company.

Bernard J. Kennedy [7]
Chairman of the Board of Directors of the Company from March 1989 to January 2, 2002, Chief Executive Officer from August 1988 to October 2001, and President from January 1987 to July 1999. Chairman of the Board of Associated Electric & Gas Insurance Services Limited. Director of the Gas Technology Institute, Interstate Natural Gas Association of America, and Merchants Mutual Insurance Company.

Bernard S. Lee, PhD [2]
Former President of the Institute of Gas Technology. Board member since 1994. Director of NUI Corporation and Peerless Manufacturing Company.

Eugene T. Mann [3, 5, 7]
Retired Executive Vice President of Fleet Financial Group. Board member since 1993.

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

John F. Riordan [1]
President and Chief Executive Officer of the Gas Technology Institute since April 2000. Board member since July 2000. Director of Nicor Inc., Niagara University, and the Oral and Maxillofacial Surgery Foundation.

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 Policy and Corporate Governance Committee
8 Chairman, Policy and Corporate Governance Committee

Common Stock Transfer Agent and Registrar*

Computershare Investor Services, LLC
P.O. Box A3504
Chicago, IL 60690-3504
Tel. (800) 648-8166
Web site at:
http://www-us.computershare.com/investors
E-mail: web.queries@computershare.com

**Change-of-address notices and inquiries about dividends should be sent to the Transfer Agent at address shown.*

Stock Exchange Listing

New York Stock Exchange (Stock Symbol: NFG)

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 Computershare Investor Services, LLC, the agent for the Plan, at:

Computershare Investor Services, LLC
P.O. Box A3309
Chicago, IL 60690-9994
Tel. (800) 648-8166
E-mail: web.queries@computershare.com

Trustee for Debentures

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

Independent Accountants

PricewaterhouseCoopers LLP
3600 HSBC Center
Buffalo, NY 14203

Annual Meeting

The Annual Meeting of Shareholders will be held at 10 a.m. (local time) on Thursday, February 21, 2002, at the offices of Akin, Gump, Strauss, Hauer & Feld, L.L.P., 1900 Pennzoil Place, South Tower, 711 Louisiana Street, Houston, Texas 77002. Formal notice of the meeting, proxy statement and proxy will be mailed to shareholders of record as of December 24, 2001.

Investor Relations

Investors or financial analysts desiring information should contact:

Joseph P. Pawlowski
Treasurer
Tel. (716) 857-6904

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

National Fuel Gas Company
10 Lafayette Square
Buffalo, NY 14203

Additional Shareholder Reports

Additional copies of this report and the Financial and Statistical Supplement to the 2001 Annual Report can be obtained without charge by writing to or calling:

Anna Marie Cellino
Corporate Secretary

National Fuel Gas Company
10 Lafayette Square
Buffalo, NY 14203
Tel. (716) 857-7858

This Annual Report and the statements contained herein are submitted for the general information of shareholders and employees of the Company and are not intended to induce any sale or purchase of securities or to be used in connection therewith.

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 has an Internet Web site at* **http://www.nationalfuelgas.com.** *You may sign up there to automatically receive news releases by e-mail. Simply go to the* **News & Info** *section and subscribe.*

Printed on Recyclable Paper with Soybean Inks

National Fuel

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