MDU RESOURCES GROUP, INC.

Building a Strong America

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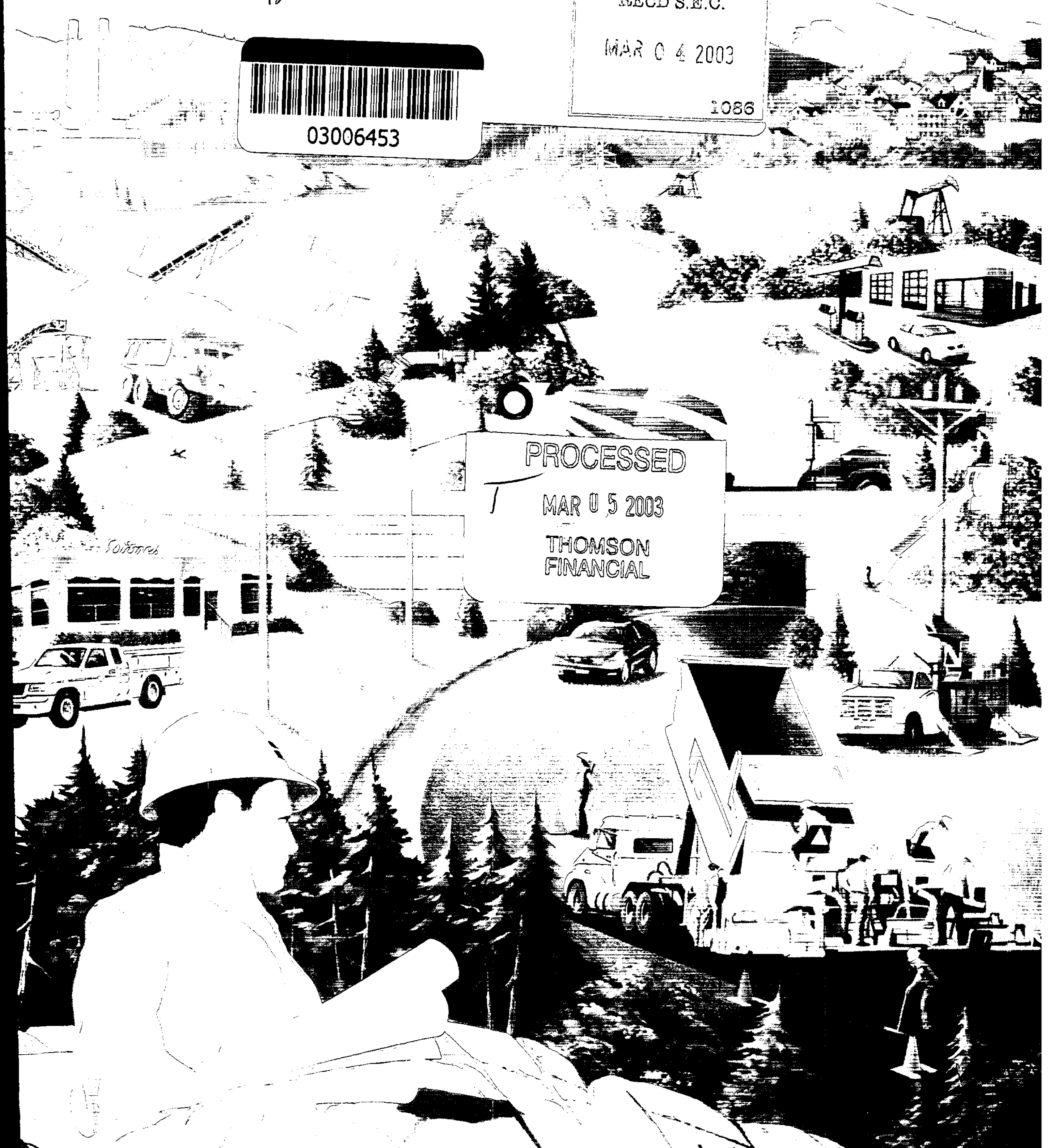
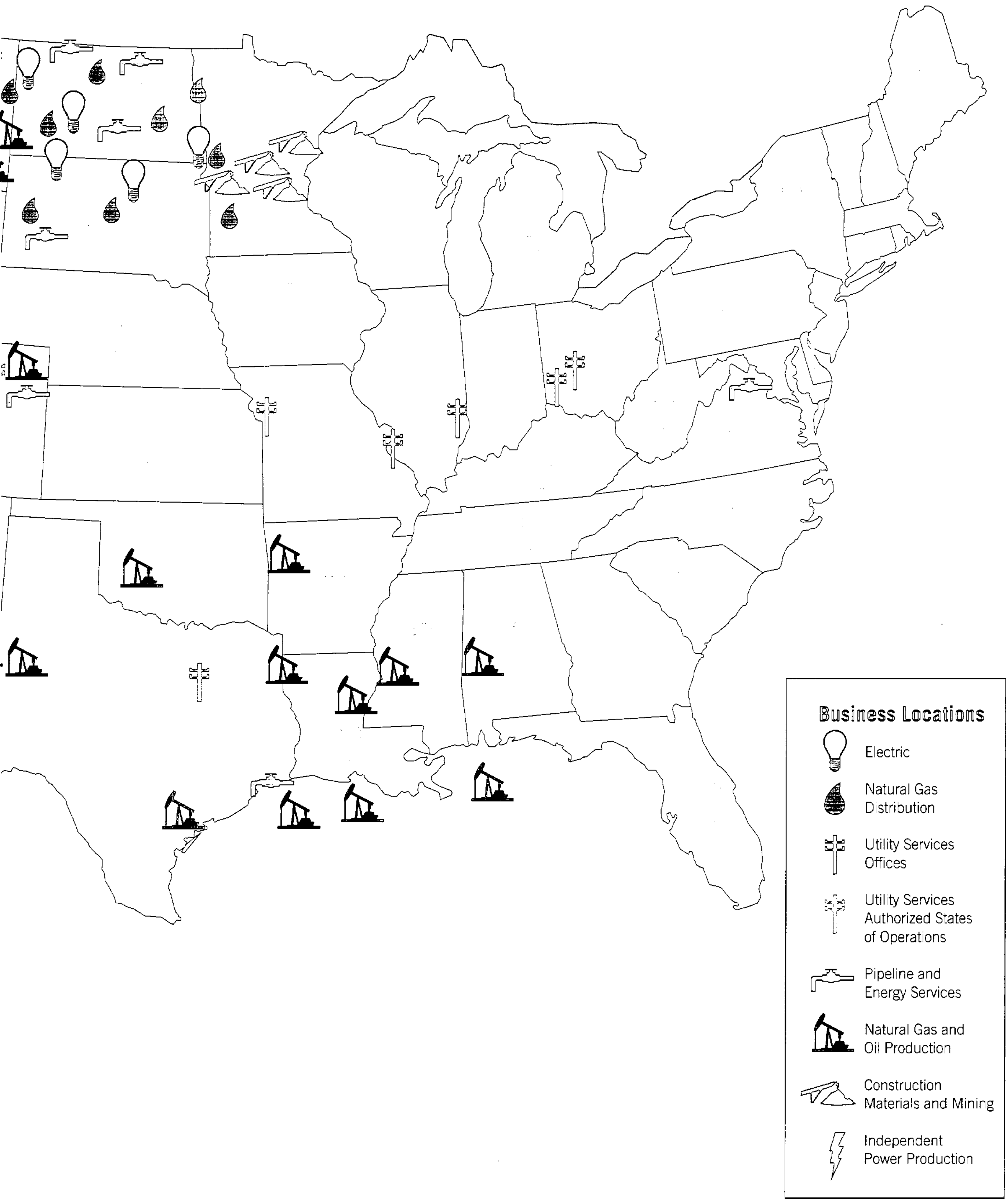


2002 ANNUAL REPORT

Building a Strong America



MDU Resources Group, Inc.

Our Vision

With integrity, create superior shareholder value by expanding upon our expertise to be the supplier of choice in all of our markets while being a safe and great place to work.

Our Mission

Provide value-added natural resource products and related services that exceed customer expectations.

To achieve this mission we will be guided by commitments to:

Customers: Provide high-quality, cost-effective products and services.

Stockholders: Produce a superior total return.

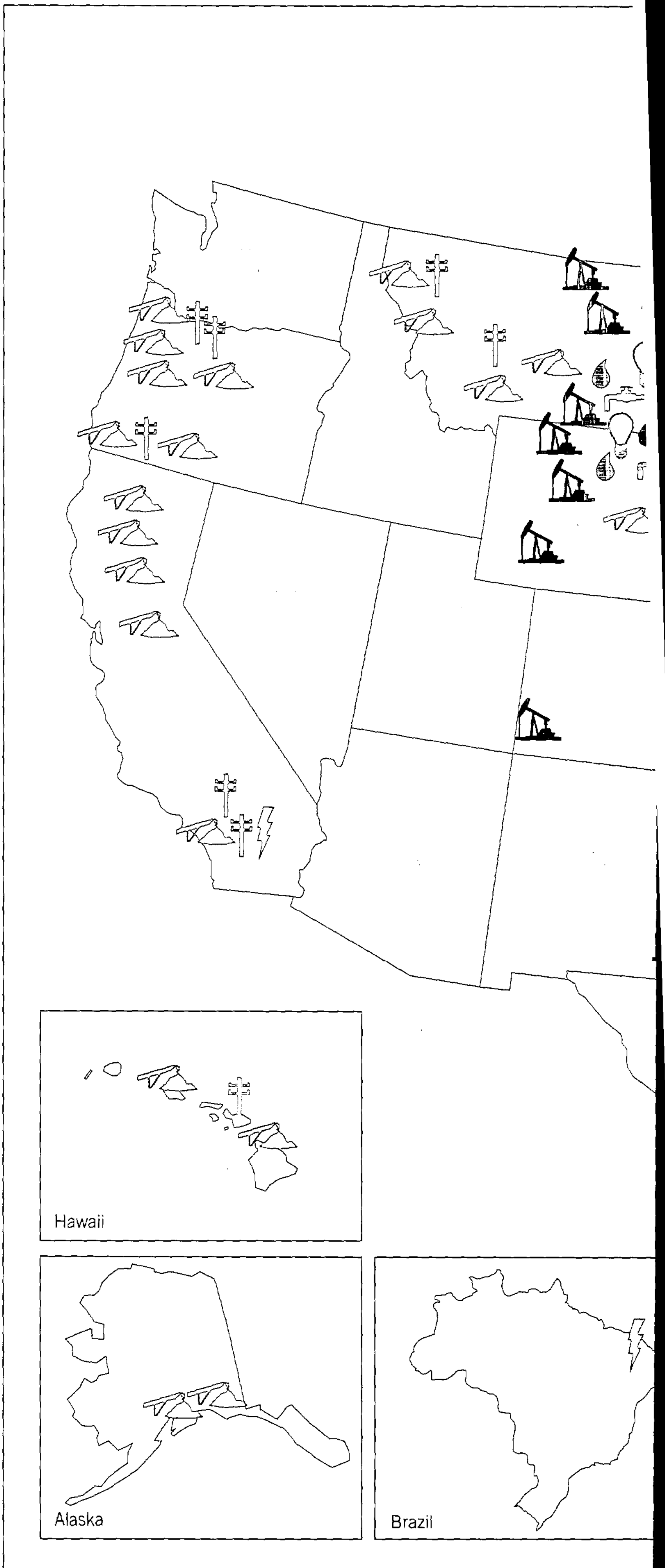
Community: Recognize our responsibility to be an effective corporate citizen.

Environment: Minimize waste and maximize resources.

Ethics: Conduct business with integrity and with respect for all.

Employees: Develop individual potential and teamwork to maintain employees as our ongoing source of competitive advantage.

Safety: Perform all tasks with health and safety first.



MDU Resources Group, Inc.

MDU Resources Group, Inc. provides energy, value-added natural resource products and related services that are essential to our country's energy, transportation and communication infrastructure.

MDU Resources includes electric and natural gas utilities, a natural gas pipeline, utility services, natural gas and oil production, construction materials and mining, energy services, and domestic and international independent power production.

On the Cover: The illustration is a snapshot of a typical American landscape, supported by the infrastructure that is essential to our daily life. If you look closely, you will find representation of all the various lines of business in which MDU Resources operates. Our employees help provide America with conveniences and necessities that make our lives better and make the United States a great country in which to live and do business. The employees of the MDU Resources' family of companies are proud to be part of a team that helps in **Building a Strong America**.

MDU Resources designs, builds, maintains and operates facilities that are part of our country's modern infrastructure. The company reflects a multi-dimensional enterprise: regulated and nonregulated businesses operating in different geographic locations and selling a broad spectrum of high-quality products and services.

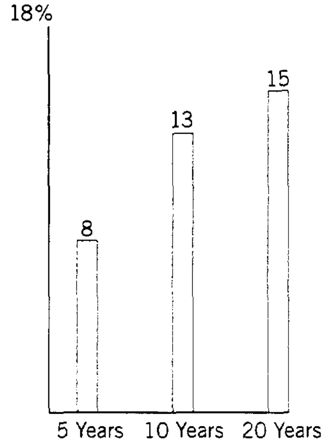
Visit www.mdu.com for updated financial and operating information.

Highlights

Years ended December 31,	2002	2001	Increase/Decrease Amount	Increase/Decrease Percent
	(In millions, where applicable)			
Operating revenues:				
Electric	$ 162.6	$ 168.8	$ (6.2)	(4)
Natural gas distribution	186.6	255.4	(68.8)	(27)
Utility services	458.7	364.8	93.9	26
Pipeline and energy services	165.2	531.1	(365.9)	(69)
Natural gas and oil production	203.6	209.8	(6.2)	(3)
Construction materials and mining	962.3	806.9	155.4	19
Independent power production	6.8	–	6.8	–
Intersegment eliminations	(114.3)	(113.2)	(1.1)	(1)
Total	$2,031.5	$2,223.6	$(192.1)	(9)
Operating income:				
Electric	$ 33.9	$ 38.7	$ (4.8)	(12)
Natural gas distribution	2.4	3.6	(1.2)	(32)
Utility services	14.0	25.2	(11.2)	(45)
Pipeline and energy services	39.1	30.4	8.7	29
Natural gas and oil production	85.6	103.9	(18.3)	(18)
Construction materials and mining	91.4	71.5	19.9	28
Independent power production	(.3)	–	(.3)	–
Total	$ 266.1	$ 273.3	$ (7.2)	(3)
Earnings on common stock:				
Electric	$ 15.8	$ 18.7	$ (2.9)	(16)
Natural gas distribution	3.6	.7	2.9	430
Utility services	6.4	12.9	(6.5)	(51)
Pipeline and energy services	19.1	16.4	2.7	16
Natural gas and oil production	53.2	63.2	(10.0)	(16)
Construction materials and mining	48.7	43.2	5.5	13
Independent power production	.9	–	.9	–
Total	$ 147.7	$ 155.1	$ (7.4)	(5)
Earnings per common share:				
Basic	$ 2.09	$ 2.31	$ (.22)	(10)
Diluted	$ 2.07	$ 2.29	$ (.22)	(10)
Dividends per common share	$ .94	$ .90	$ .04	4
Weighted average common shares outstanding – diluted	71.2	67.9	3.3	5
Total assets	$2,937.2	$2,623.1	$ 314.1	12
Total equity	$1,298.7	$1,124.8	$ 173.9	15
Net long-term debt	$ 819.6	$ 783.7	$ 35.9	5
Capitalization ratios:				
Common equity	60%	58%		
Preferred stocks	1	1		
Long-term debt	39	41		
	100%	100%		
Return on average common equity	12.5%	15.3%		
Price/earnings ratio	12.5x	12.3x		
Book value per common share	$ 17.34	$ 15.90		
Market value as a percent of book value	148.8%	177.0%		
Full-time employees	6,983	6,568		

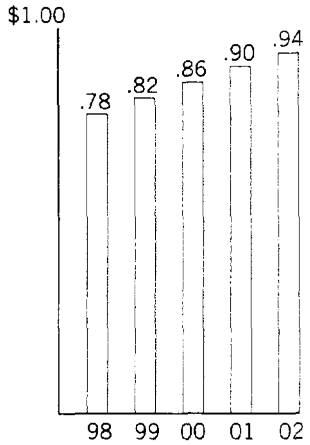
This Annual Report contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in Management's Discussion and Analysis – Risk Factors and Cautionary Statements that May Affect Future Results. Forward-looking statements are all statements other than statements of historical fact, including without limitation, those statements that are identified by the words *anticipates, estimates, expects, intends, plans, predicts* and similar expressions.

Annual Total Stockholder Return
(Percent)



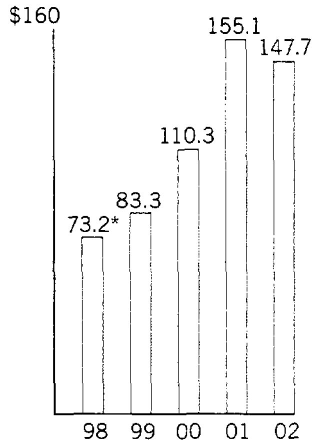
Long-term stock price appreciation and dividends benefit stockholders.

Dividends
(Dollars per common share)



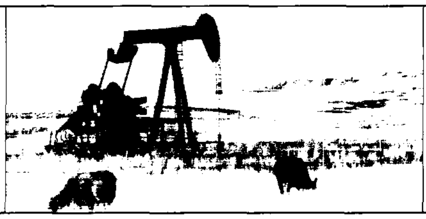
Dividends have increased 20 percent since 1998.

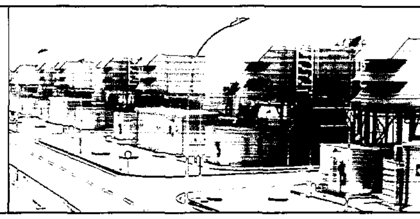
Earnings
(Dollars in millions)



Earnings reflect the company's successful growth strategy.

*Excludes $39.9 million in noncash after-tax write-downs of natural gas and oil properties.





Natural Gas and Oil Production

Fidelity Exploration & Production Company is engaged in natural gas and oil acquisition, exploration and production activities primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico.

2002 Key Statistics

Revenues *(millions)*	$203.6
Earnings *(millions)*	$53.2
Production:	
Natural gas *(Bcf)*	48.2
Oil *(million barrels)*	2.0
Net recoverable reserves:	
Natural gas *(Bcf)*	372.5
Oil *(million barrels)*	17.5
Corporate earnings contribution	36%

Major Customers

- Energy marketers
- End-use customers
- Natural gas utilities
- Oil refineries

Competition

- Independent natural gas and oil companies such as XTO; Tom Brown Inc.; St. Mary Land & Exploration Company; and Patina Oil & Gas Corporation

○ Area of principal production and reserves

Construction Materials and Mining

Knife River Corporation mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt and other value-added products, as well as performing integrated construction services, in the north central and western United States, including Alaska and Hawaii.

2002 Key Statistics

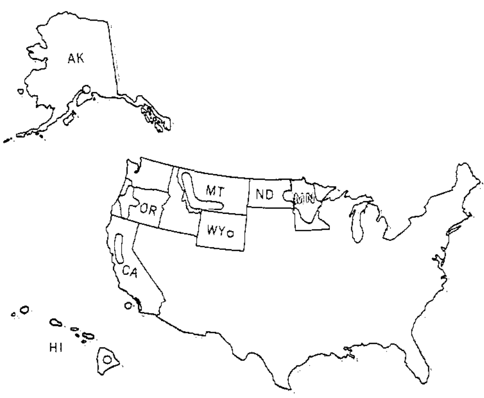
Revenues *(millions)*	$962.3
Earnings *(millions)*	$48.7
Sales *(millions)*:	
Aggregates *(tons)*	35.1
Asphalt *(tons)*	7.3
Ready-mixed concrete *(cubic yards)*	2.9
Recoverable aggregate reserves *(billion tons)*	1.1
Corporate earnings contribution	33%

Major Customers

- Federal, state and local highway contractors
- Commercial builders
- Site developers

Competition

- Other construction materials companies such as LaFarge Corporation, Vulcan Materials Company, Martin Marietta Materials, Rinker Materials Corporation, Oldcastle Inc. and Teichert, Inc.



○ Construction materials locations

Independent Power Production

Centennial Energy Resources owns electric generating facilities in the United States and Brazil. Electric capacity and energy produced at these facilities is sold under long-term contracts to nonaffiliated entities. This segment also invests in potential new growth and synergistic opportunities that are not directly being pursued by other business segments.

2002 Key Statistics*

Revenues *(millions)*	$6.8
Earnings *(millions)*	$.9
Electricity produced and sold *(million kWh)*	15.8
Corporate earnings contribution	1%

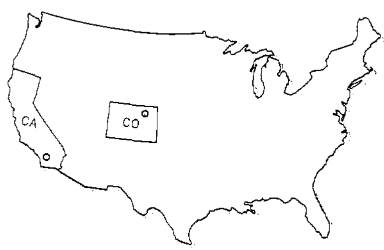
**Reflects international operations for 2002 and domestic operations acquired in November 2002. The earnings from the Company's equity method investment in Brazil were included in other income – net.*

Major Customers

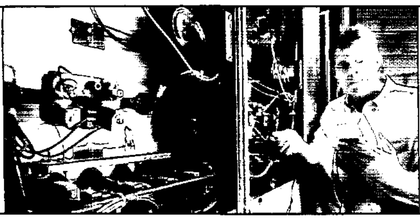
- Nonaffiliated electric utility and other energy companies, including Public Service Company of Colorado and Petrobras

Competition

- Other independent power producers who operate power plants under contract to nonaffiliated utilities



○ Independent power production locations



Electric and Natural Gas Distribution

Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. distribute natural gas and provide related value-added products and services in the northern Great Plains. Montana-Dakota also generates, transmits and distributes electricity.

2002 Key Statistics

Revenues *(millions)*:	
Electric	$162.6
Natural gas distribution	$186.6
Earnings *(millions)*:	
Electric	$15.8
Natural gas distribution	$3.6
Electric sales *(million kWh)*:	
Retail	2,275.0
Sales for resale	784.6
Natural gas sales and transportation *(MMdk)*:	53.3
Corporate earnings contribution:	
Electric	11%
Natural gas distribution	2%

Major Customers

- Electric customers:

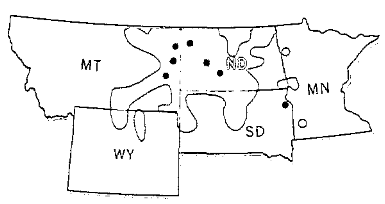
Residential	96,510
Commercial	17,778
Industrial and other	2,222

- Natural gas customers:

Residential	212,467
Commercial	27,475
Industrial and other	120

Competition

- Electric:
  Other electric utilities, including rural electric cooperatives
- Natural gas distribution:
  Other energy providers, including propane and fuel oil dealers, electric utilities and rural electric cooperatives



○ Electric & natural gas distribution area
● Electric generating stations

Utility Services

Utility Services, Inc. is a diversified infrastructure company specializing in electric, gas and telecommunication utility construction, as well as industrial and commercial electrical, exterior lighting and traffic signalization throughout most of the United States. The company also provides related specialty equipment manufacturing, sales and rental services.

2002 Key Statistics

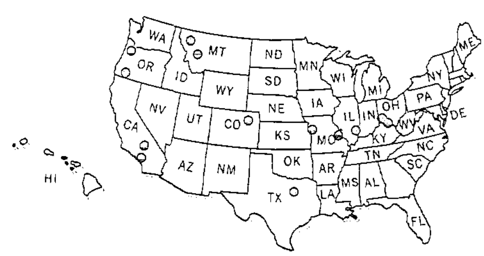
Revenues *(millions)*	$458.7
Earnings *(millions)*	$6.4
Corporate earnings contribution	4%

Major Customers

- Electric utilities
- Natural gas utilities
- Telecommunications companies
- Municipalities
- Industrial and commercial electrical contractors

Competition

- Other utility services contractors such as Quanta Services, Inc.; MYR Group Inc.; Exelon Infrastructure Services, Inc.; MasTec, Inc.; Dycom Industries, Inc. and other industrial and commercial electrical contractors



○ Utility services offices
State names indicate authorized states of operation

Pipeline and Energy Services

WBI Holdings, Inc. provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The company also provides energy-related management services, including cable and pipeline magnetization and locating.

2002 Key Statistics

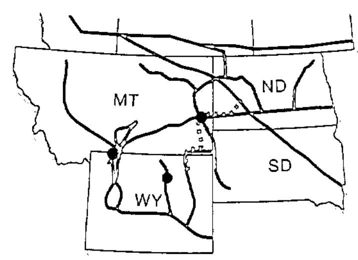
Revenues *(millions)*	$165.2
Earnings *(millions)*	$19.1
Transportation *(MMdk)*	99.9
Gathering *(MMdk)*	72.7
Corporate earnings contribution	13%

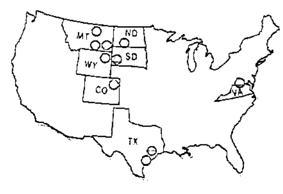
Major Customers

- Natural gas utilities
- Industrial gas users
- Commercial gas users
- Municipal gas systems
- Natural gas marketers

Competition

- Other natural gas pipeline companies such as Kinder-Morgan, Inc.; Northern Border Pipeline Company; Questar Pipeline; and Colorado Interstate Gas Company



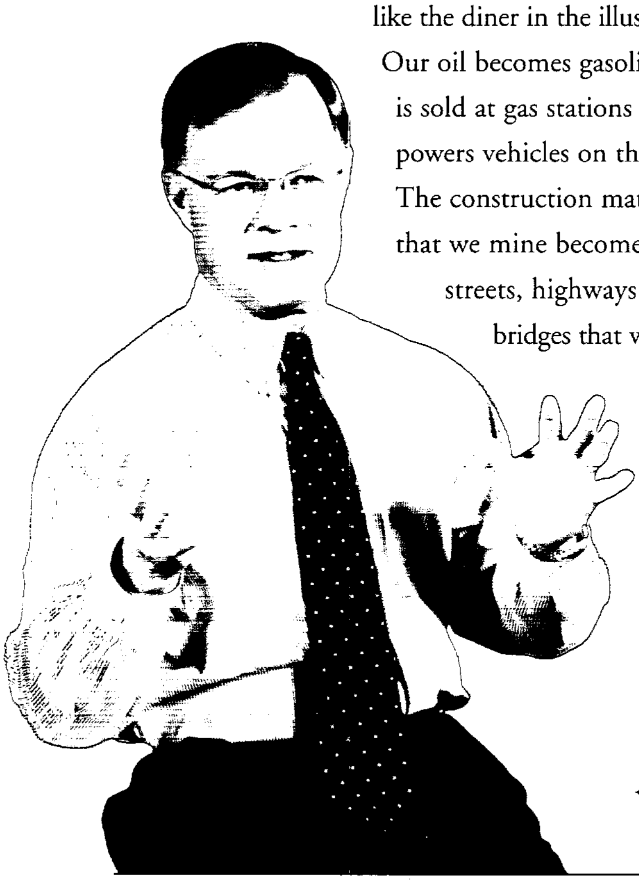


— Transmission pipeline system
— *Interconnecting pipelines*
··· Proposed pipeline
● Company storage fields
○ Energy services offices
○ Pipeline gathering systems

We are the picture of a company that is building a strong America

There's a song that begins, "If a picture paints a thousand words." I think of that when I look at our annual report cover. A big part of my job is talking to people about our company. Sometimes it's a challenge to succinctly describe everything that we do and how it all fits together. I know I use more than 1,000 words. But if you study the cover, your picture of our company will become clearer.

The well-done cover illustration shows how we help build and support America's infrastructure. We operate power plants that generate electricity used by customers in many towns that dot our nation's countryside. We explore for and produce oil and natural gas. Much of our natural gas moves through our compressor stations and pipelines. We distribute natural gas and electricity to homes and businesses like the diner in the illustration. Our oil becomes gasoline that is sold at gas stations and powers vehicles on the road. The construction materials that we mine become the streets, highways and bridges that we build.



◁ Martin A. White, Chairman of the Board, President and Chief Executive Officer

We construct streetlights and electric distribution and transmission lines like those on the cover. We also build natural gas distribution lines, wiring and telecommunications lines that are underground.

America is stronger because of businesses like ours. Everything that we do supports our nation's infrastructure. Everything that we do follows the first two words of our vision statement "with integrity." That's important to our country, our stockholders and our employees.

This year, Congress and regulatory agencies placed new emphasis on more accountability of publicly traded companies. We were pleased to see we already live by the majority of the new requirements; they're part of our culture. I encourage you to read the special section on corporate accountability in this document. It defines what we are doing in this arena.

Overall, I'm pleased with our 2002 results. Earnings were $147.7 million for 2002, compared to $155.1 million for 2001. Earnings per common share, diluted, totaled $2.07, compared to $2.29 per common share, diluted, for 2001. This performance is especially

Everything that we do follows the first two words of our vision statement "with integrity."

satisfying in a year when the Standard & Poor's 500 index declined 22 percent. Our returns declined less than 5 percent, and we outperformed our peer group.

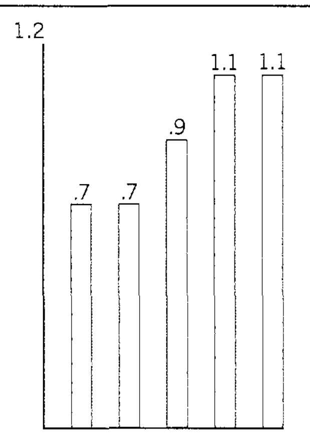
In August, our Board of Directors increased the dividend 4 percent, marking the 12th consecutive year that the company has increased dividends. MDU Resources has an unbroken record of quarterly dividend payments since 1937.

In 2002, MDU Resources was named to Fortune's list of the "100 Fastest-Growing Companies." The magazine ranks U.S.-based, publicly traded companies on a variety of factors, including earnings per share growth of at least 25 percent for three straight years and total returns to investors. We also were named to the Forbes magazine "Platinum List of America's 400 Best Big Companies" for the third consecutive year. In addition, our investor relations program was recognized by Treasury & Risk Management magazine with its Alexander Hamilton Award for best practices.

Despite a slow economy and lower natural gas and oil prices, MDU Resources had respectable earnings. Each business unit and every employee recognized that the country was facing challenges that could affect our businesses. They recognized that we needed to pull together and be innovative in order to succeed in times like these. I am happy to report that is exactly what happened.

Our construction materials and mining segment brought in record earnings of $48.7 million, a 13 percent increase over 2001. Increased aggregate, asphalt and cement sales volumes were a major factor, as were construction revenues from several large projects in California and Oregon. Existing operations were responsible for the majority of the earnings increase, with operations on the West Coast and in Hawaii reporting exceptional results. Acquisitions, especially in Minnesota, also added to the earnings gain. We expect earnings to continue at or near that level in 2003. While the current highway funding bill expires this year, we anticipate reauthorization of federal highway funding at least at current levels. We have more than 1 billion tons of strategically located permitted reserves, representing a 30- to 40-year supply – a tremendous asset for our company.

Aggregate Reserves
(In billion tons)



Substantial aggregate reserves build shareholder value.

The pipeline and energy services segment's earnings were $19.1 million for 2002, a 16 percent increase over 2001. Record volumes of natural gas were transported and gathered at higher average rates this year, with higher storage revenues realized as well. A planned 247-mile pipeline to transport additional natural gas to market and to enhance the use of the company's storage facilities is under regulatory review.

Our natural gas and oil segment's production increased 14 percent in

Jayden Veil, (L) Linda Donlin and Floyd Wilson are members of the Group Genius Innovation Committee, which reviews employees' new business ideas.

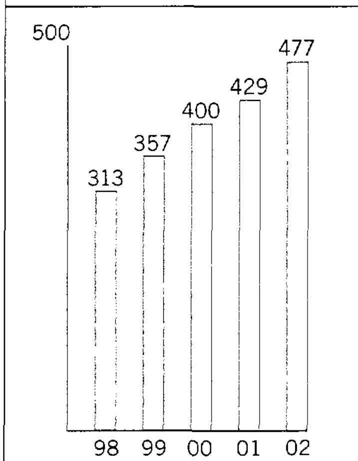
We believe there is a bright future ahead for companies like ours,

2002, producing earnings of $53.2 million. However, earnings declined primarily because realized natural gas prices were 28 percent lower and oil prices were 7 percent lower than last year. Natural gas production at our company-operated properties in the Rocky Mountain region posted an impressive growth rate of 55 percent. We plan to continue to look for opportunities to grow our valuable reserves and to use our expertise to increase production in the future.

Our public utility division's electric earnings of $15.8 million were down 16 percent this year, largely due to wholesale electric prices that were 34 percent lower than in 2001. Natural gas distribution earnings were $3.6 million, a return to more normal levels. Regulators have approved rate increases in certain jurisdictions, with others pending. I am optimistic about next year's results for this business segment.

Earnings at our independent power production segment were $.9 million. The majority of these earnings came from newly acquired electric generating facilities in Colorado.

Natural Gas & Oil Reserves
(In Bcfe)



Natural gas and oil reserves have increased 53 percent since 1998.

Our utility services segment's earnings were $6.4 million in 2002, compared to $12.9 million in 2001. This decrease was due primarily to a slowdown in telecommunications, inside electrical and engineering services work. Increased utility workloads, particularly in the Southwest and Northwest regions of the United States, were a bright spot in the picture.

Pick up any newspaper today, and you'll see that all the experts have different views about where our economy is heading. One thing that we've learned at MDU Resources is that it's important to pay attention to our own business. We haven't let the world force us to do things that we didn't think made sense, but that doesn't mean we've been stagnant or overly cautious. It's management's responsibility to find the right balance between optimism and caution. As a result, we've been successful in a soft economy.

I believe we need to be continually evolving our business, to evaluate what we're doing and where we're going. Some businesses only do this in times of crisis. At MDU Resources, Cynthia Norland, senior attorney and assistant secretary, is responsible for administering the company's Learn the Law Program.

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whose assets are rock solid and whose values have withstood the test of time.

it's a daily process. Our philosophy of building on our expertise has proven itself. We've taken that expertise and used it to grow our company both vertically and horizontally. We've focused on employee excellence and innovation by starting programs such as Group Genius, which encourages employees to share their new ideas with the company. We're shaping our company's future leaders through a corporate-wide mentoring program. We're continuing our efforts to make our corporation a Great Place to Work™ by surveying employees and listening to their concerns and suggestions. We re-emphasized our commitment to a safe workplace by changing our vision statement to prominently include safety and by increasing communication about working safely.

I believe we wouldn't have achieved what we have without making changes. The disciplined approach that we've used in acquiring companies and building new lines of business has contributed to our success and will continue to do so.

In 2003, we plan to grow our independent power production segment both domestically and internationally. We believe that changes in the electric industry have created a buyer's market for those who are focused and diligent. We also are looking at growing the market share of our construction materials segment. Our country's aging infrastructure will create more opportunities to build electric and gas lines as well as roads and bridges. New technology, such as new ways to produce natural gas or smart highways that move traffic faster and safer, will be a significant part of our next decade.

We believe there is a bright future ahead for companies like ours, whose assets are rock solid and whose values have withstood the test of time. We know that we are the perfect illustration of a business that builds and supports the very foundation of America – its infrastructure. Just as an artist brings a painting to life by paying close attention to its fine details, our focused attention on our business helps bring life to our stockholders' and employees' hopes and dreams and builds a stronger America.

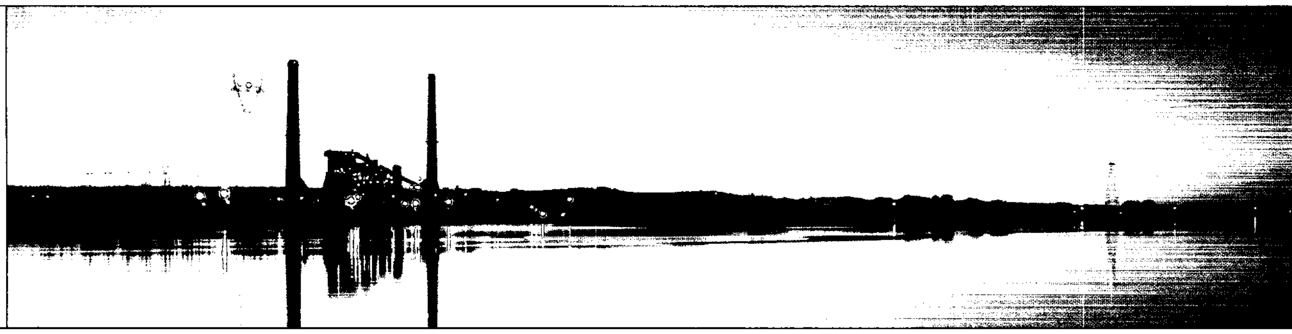
I am very proud, and indeed privileged, to lead the outstanding employees of our company to build value for this great country and our stakeholders.

Martin A. White

Martin A. White
Chairman of the Board, President and Chief Executive Officer
February 17, 2003

Exceeding customer expectations while providing America's essential energy services

America's Heartland needs reliable electricity and natural gas service to prosper. Montana-Dakota Utilities Co. and Great Plains Natural Gas Co. have been providing these essential services to their customers for decades. The company's customers know that when they flip the light switch, the lights will come on. When they turn up the heat, their natural gas-fueled furnace will provide warmth. When they start their machines, they can depend on their energy supplier to power their businesses.



△ Being a low-cost provider of electricity begins at the power plant. Strict attention to scheduled maintenance and efficiency gains have allowed Montana-Dakota to hold rates stable.

While the population base in the area hasn't changed dramatically, the company is still growing because its customers are buying more services in addition to the natural gas and electricity on which they know they can depend. The nonregulated side of the business includes appliance sales as well as service and repair. Both are exceeding expectations, and that success is primarily due to the dedication of employees.

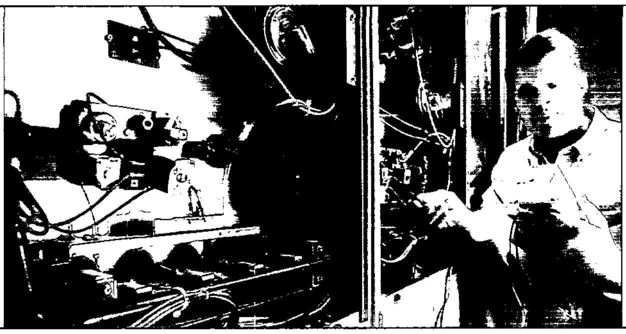
Employees recognize the importance of giving outstanding service, and they do that every day. Each person, no matter what job he or she does, knows how important it is to meet customers' expectations. Not only will the employees service their appliances and furnaces, but they also will help customers choose and finance a reliable replacement when the time comes. The company's employees aren't just a workforce, they're service providers and sales consultants. In fact, appliance sales were $3.7 million this year – an 86 percent increase since 2001, even though the company doesn't have a sales force specifically dedicated to sales.

Technology brings efficiencies

The use of new technology fuels the company's efficiency gains. Electronic work-management systems in construction vehicles cut down on paperwork, and computers in service vehicles save time and money. The company's call center topped Edison Electric Institute's list of top performers based on how quickly it handles customer calls, which is in 135 seconds – about half the national average. The company's power

Appliance sales increased 86 percent

Technicians like Lyle Partin provide a full line of customer energy services, a fast-growing nonregulated business line.



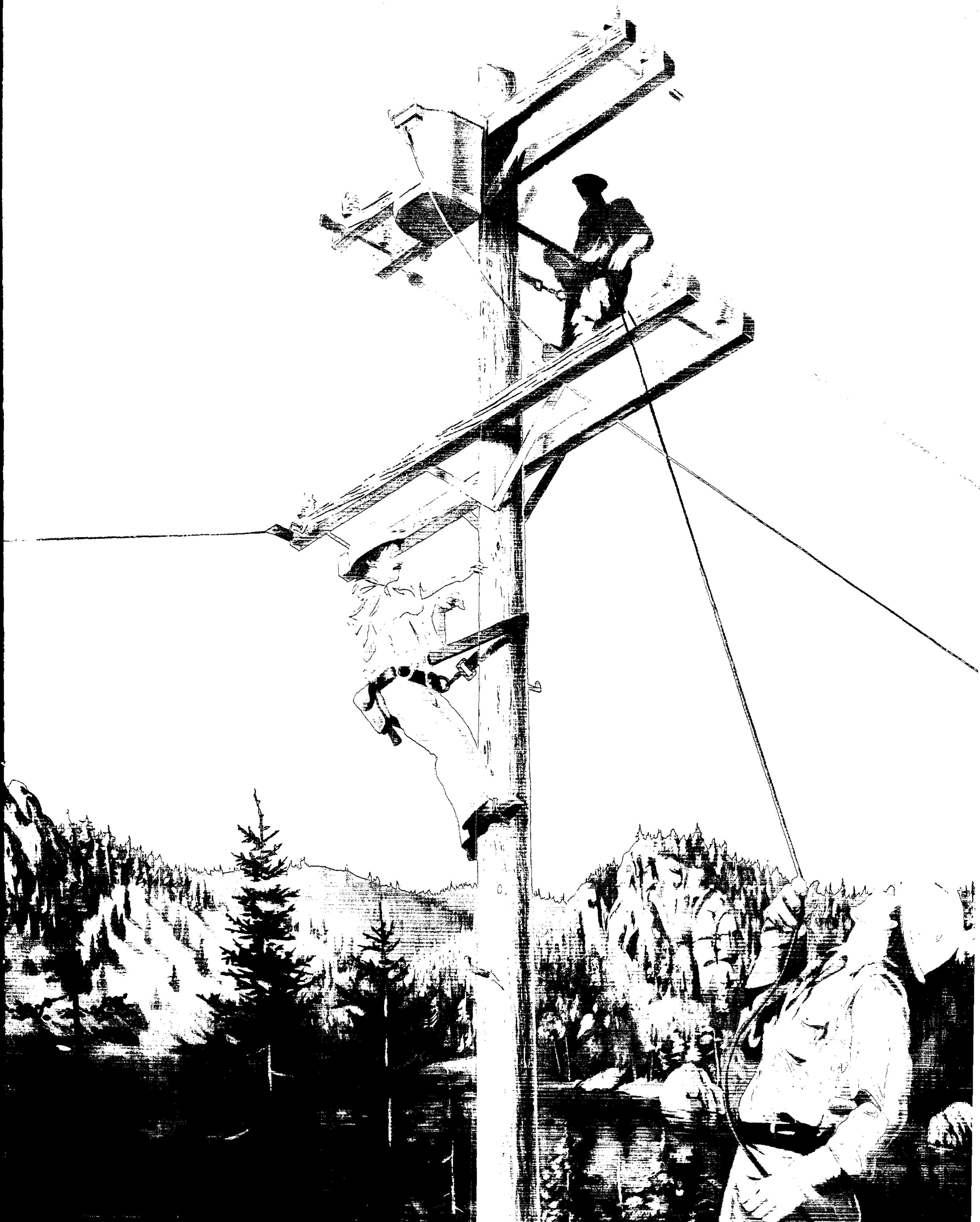
Tiffane Morris uses a palm-held computer to read meters. Technology helps hold down costs and keeps energy affordable.

plants use state-of-the-art technology to keep their availability levels at 93.6 percent, compared with the national average of 86.2 percent.

Building for the future

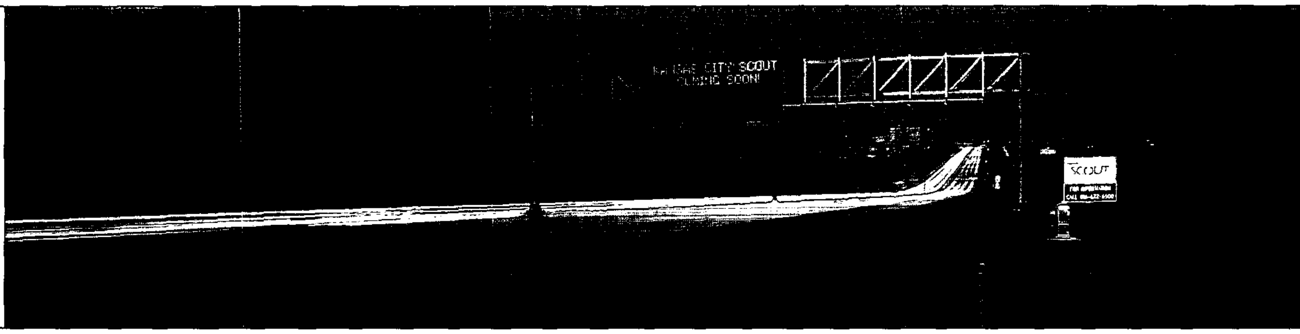
In order to serve customers into the future, the company must provide a solid base. A new summer electric peak was set for the fourth year in a row, indicating growing demand. Rather than buying more power from others, the company has decided to control its own destiny by building a 40-megawatt, natural gas-fired combustion turbine generator in Montana that will be in service in 2003. The company signed a contract to purchase the output from a 20-megawatt wind farm in North Dakota, the first large-scale wind energy project in the state. It also is studying the feasibility of building a 250-megawatt or 500-megawatt, lignite-fueled power plant in southwestern North Dakota.

By investing in its own generation and continuing its commitment to purchase low-cost natural gas supplies, the company is ensuring that its customers will have stable, long-term, competitive rates. These commitments, combined with the determination of employees to give exceptional service, are what help keep America strong.



Upgrading America's infrastructure using new technology, old-fashioned know-how

There are few things that are as essential to the infrastructure of this country as the power lines that connect us, the natural gas lines that bring fuel to us or the telecommunications lines that move data from one place to another. The companies that make up Utility Services, Inc. (USI) design and build these vital networks and provide specialized products and services that support them. USI's internal expertise, comprehensive line of services and diverse geographical locations help bring greater stability to operations.



△ Kansas City motorists will enjoy Kansas City Scout, a new, fully operational traffic management system, scheduled for completion by the end of 2003. Capital Electric, a USI subsidiary, is the general contractor for this $25 million project.

Building on the corporation's expertise in electric and natural gas line construction, USI has grown from its startup in 1997 with the acquisition of two line-building companies in Oregon to a company that has offices in eight states and operations around the country. Together they provide a diverse menu of products and services.

USI's philosophy has been to acquire stable, well-run companies with a track record of giving their customers quality service. As each company was acquired, USI's menu of services grew and its geographic diversity expanded. Operations are in major growth areas and offer customers services such as construction and engineering of electrical, natural gas, telecommunications and transportation systems, along with manufacturing, sales and rental of related equipment.

This focused acquisition philosophy has paid off, particularly in this time of economic downturn and instability in the energy and telecommunications industries. The nation's infrastructure must be maintained, and in unstable times, customers want stability from their service providers. USI's customers know they can depend on the company to give them the service they need when and where they need it.

Geographic diversity proves valuable

The advantage of geographic diversity has proven itself in the past two years. Last year, inside electrical

Revenues total $459 million in sixth year of operations

Fabricating and installing precision instrumentation is the craft of Martin Clemans at Oregon Electric, a subsidiary of USI.

Wagner-Smith Equipment, a USI company, manufactures electric line tensioning equipment for sale and lease.

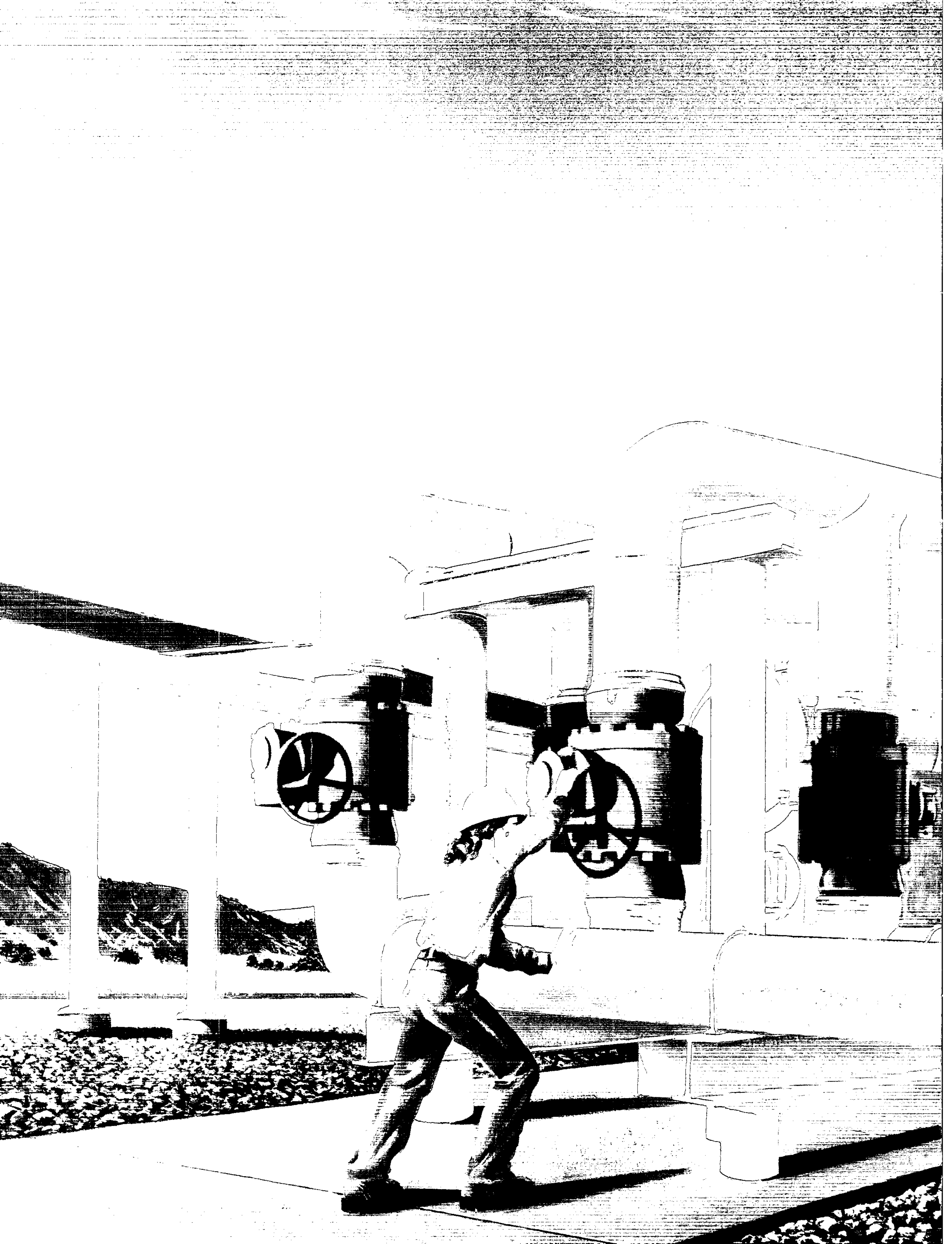
wiring was in high demand in the company's Midwest operations, and the electric line-building business on the West Coast was down. This year, just the opposite was true.

Old-fashioned know-how, which comes from the seasoned management and skilled employees at each USI company, combined with the use of new technology in rebuilding and updating worn-out or outdated sections of the nation's infrastructure, is one of the keys to the company's success. An example is the smart highway system that Capital Electric Line Builders is constructing in Kansas City. This $25 million project uses technology in roadways to help move larger amounts of traffic more efficiently.

Disciplined acquisitions and operations

In a tumultuous year for the industry, USI has been successful because of its disciplined acquisition and operations philosophies. This creates opportunities for future acquisitions, and the company's plans are to watch and wait for stable companies in the right markets. In addition to its regular customers, USI is seeing growth in the installation of security systems and video surveillance equipment.

A primary challenge ahead will be distinguishing the company in the eyes of the financial community from similar companies that have not dealt with the struggling economy as well as USI.



Delivering natural gas safely and reliably is vital to America's homes and businesses

A vast network of pipelines through which WBI Holdings, Inc. provides natural gas transportation, storage and gathering services supplying critical connections for consumers in the northern United States. WBI Holdings' subsidiary companies also provide energy-related management services including cable and pipeline magnetization and locating for customers all over the world.

△ Tony Finneman, (L) and Mark Makelky, project leaders for the proposed Grasslands Pipeline, survey the proposed route through beautiful – but difficult – terrain.

Record amounts of natural gas flowed through the company's pipelines in 2002. Low natural gas prices prompted large customers to buy supplies in advance and store them. Transporting these supplies to and from our storage facilities and the growth of the natural gas and oil production segment's natural gas production from its operated properties contributed significantly to the record levels of gathered and transported natural gas. These factors also enhanced use of the company's underground storage facilities.

The strategic geographic locations of the company's pipelines are distinct advantages in moving natural gas to major markets throughout the United States. They wind their way through conventional producing fields in Colorado, Montana, North Dakota and Wyoming, as well as through the heart of the developing coalbed natural gas production area of the Powder River Basin in Wyoming and Montana.

Opportunities in relieving bottlenecks

Most of the rapidly increasing Powder River Basin production currently flows south. The company is poised to take advantage of a key opportunity to construct an alternative pipeline route to the north. Plans are in place to build a 247-mile pipeline to access mid-American markets that will help solve a transportation bottleneck out of the Powder River Basin.

This is one of the largest pipeline projects the company has undertaken, and it holds the potential to significantly increase our delivery of natural gas. It also will have positive effects on the storage portion

Earnings increased 16 percent in 2002

Record natural gas volumes traveled through 5,000 miles of the company's pipeline network in 2002.

Brad Marman monitors pipeline pressures and delivery volumes, ensuring safe and reliable service around the clock.

of the business in that more gas can be moved to storage. The company's natural gas and oil production segment also should benefit from an enhanced ability to move its product to better-priced markets. Construction is expected to begin during the summer, with the expectation that the pipeline will be in service by late 2003.

On the energy services side, the company's cable and pipeline magnetization and locating business has established itself as one of the premiere locating equipment and technology providers in the world. It currently serves a respectable portion of the world's underwater locating market. The company also is in the process of developing other new and innovative technologies that have the potential to significantly improve the terrestrial locating business.

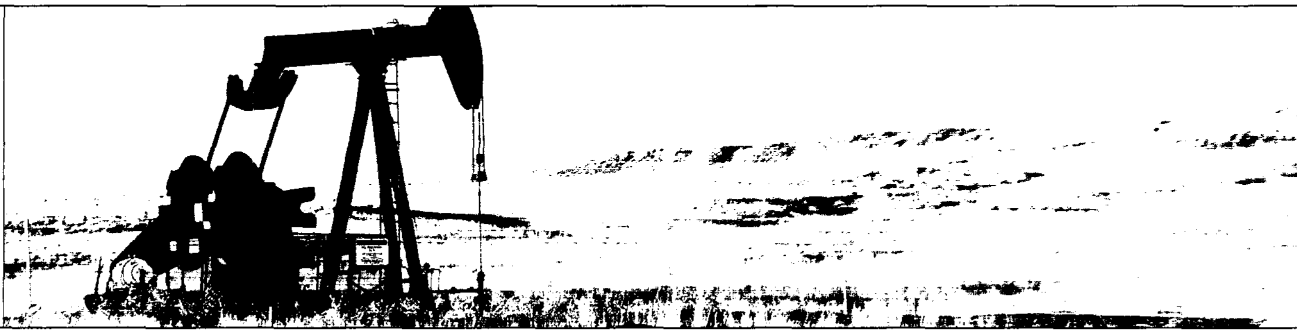
Growing internally and meeting challenges

The company is achieving internal growth through synergies by using existing resources in different ways and making the most of existing assets. An example of this is relocating compression facilities that are no longer needed at one location to other areas of the company's pipeline system.

Challenges to this business segment include maintaining adequate access to gas supplies needed by customers in locations that may be restricted due to lack of roads or that have previously been excluded from development. The economy and global events also could affect the European operations of our pipeline locating business.

Fueling America's economy with the nation's own natural gas and oil reserves

A key ingredient in the country's quest toward energy independence is producing natural gas and oil from domestic reserves. Fidelity Exploration & Production Company is a significant contributor because of its vast reserves in the Rocky Mountain region and the Gulf of Mexico. Increasing production 55 percent in its company-operated fields spotlights a successful past and a bright future.



△ With production throughout the Rocky Mountain region, like this development in northeastern Colorado, Fidelity has evolved into a significant player in the industry.

Natural gas and oil production is now approaching 200 million cubic feet equivalent per day. Reserve growth has more than offset the volumes produced. As a result, Fidelity is positioned to help supply the energy that keeps America moving.

The company produced more natural gas in Montana during 2001 than any other company operating in the state – enough natural gas to meet the annual consumption needs of about 200,000 households – and this growth continued in 2002. Fidelity is a pioneer in developing Montana's coalbed natural gas resource. In Wyoming, the company has been successfully implementing industry-leading management practices that facilitate environmentally responsible use of the produced water that is associated with coalbed natural gas production. Fidelity views the water as a valuable resource in this arid part of the United States.

Fidelity has immense reserves of more than 475 billion cubic feet of natural gas equivalent. Reserve increases point to the company's ability to expand existing resources plus acquire valuable new assets. This is the result of employees' expertise in developing and applying new technology in older fields and obtaining production growth in newer and somewhat unconventional coalbed fields.

Company-operated production increased 55 percent

Fidelity's technical expertise, illustrated through employees like Jeff Lang, asset team manager, has been responsible for enhancing production from long-lived assets.

▽

Coiled tubing fracturing treatment is a technical advancement employed by Fidelity that economically taps into bypassed reserves resulting in increased production.

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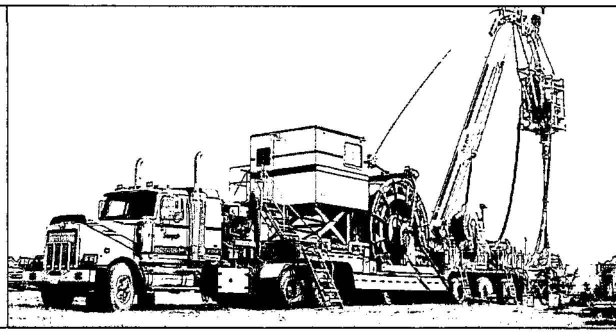


Opportunities in existing assets

Growth opportunities will be found by aggressively developing the potential drilling locations within the company's existing production areas. For example, the company's engineers already have identified more than 2,500 future drilling locations.

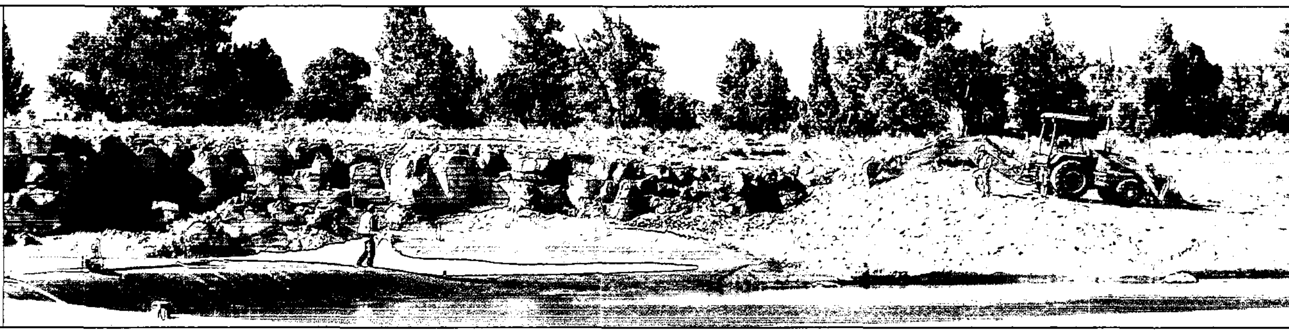
Continued consolidation within the natural gas and oil industries present opportunities in the coming years, and Fidelity will be vigilant in its search for opportunities that fit within its growth strategy. The company's solid acreage positions will be a tremendous advantage in supplying the nation's energy needs, as will its ability to complete timely and economic acquisitions. The company plans to continue to grow both its production and reserves in 2003.

Challenges to overcome

Access to drillable lands and resistance from those opposed to development of coalbed natural gas are the company's primary challenges. The limited capacity of the gas transportation and distribution infrastructure also could present problems in getting energy to the marketplace. Price volatility in the market is a challenge, as it was this year. However, Fidelity has been successful in mitigating the downside of pricing scenarios through timely and appropriate natural gas and oil hedging and fixed price contracts and will continue to aggressively pursue those efforts.

Building America's foundations by adding value to rock

Solid as a rock is the best way to describe the operations of Knife River Corporation, our construction materials and mining company. Knife River has more than a billion tons of strategically located aggregate reserves from which it adds value to the rock it mines by building roads and producing asphalt, ready-mixed concrete, concrete blocks, pre-cast concrete products, landscaping products and more.



△ Hap Taylor & Sons, Inc., a Knife River company, is constructing Oregon's first Tom Fazio Golf Course and the first Jack Nicklaus Signature Golf Course at a premier golf community in progress near Bend.

The booming housing market, fueled by low interest rates, along with construction financed by TEA-21 (Transportation Equity Act of the 21st century) helped make 2002 a record year for Knife River. While other parts of the economy slowed down, road and homebuilding remained strong, which is reflected in this segment's outstanding earnings.

Earnings benefited in the past two years from the strategic acquisitions of several Minnesota-based construction materials companies, growing the company's market area in that region to encompass a large part of the state. Also contributing to earnings were large jobs such as a harbor improvement project in Los Angeles that will require 3.5 million tons of rock.

Diversity and synergies combine for success

Geographic diversity has proven to be an important advantage, particularly last year when building slowed for a time in the Pacific Northwest but picked up in Hawaii. Weather can be a significant factor in completing projects, but with operations in seven states, the effect on earnings is minimized as weather patterns vary in different regions. Operations diversity has benefited Knife River. Its companies supply everything from raw materials to specialized resources and services necessary to complete a complex project.

In Oregon, a Knife River company is constructing the state's first Tom Fazio and Jack Nicklaus Signature Golf Courses at a premier golf community being constructed near Bend. It took more than 150,000 pounds of dynamite, 7,600 truckloads of rock,

Record earnings of $48.7 million, a 13 percent increase

More than 1 billion tons of strategically located permitted reserves provide Knife River's primary competitive advantage.

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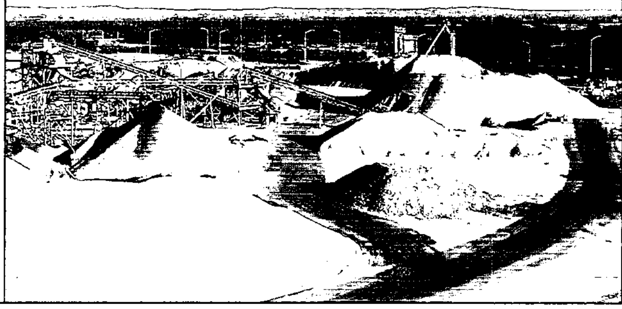


Jason Gall of Bauerly Brothers, Inc., with headquarters in St. Cloud, Minn., helps a crew pave 8.4 miles of Highway 25 south of Buffalo, Minn.

▽

4,000 hours of heavy equipment use and 500 hours of labor to create just one green on the Fazio course.

Another Oregon-based company created more than 1,380 pre-cast concrete components for the expansion of Autzen Stadium, home of the University of Oregon Ducks football team. Structural supports featured a unique "Y" column configuration that was too large to ship to the site in one piece. The columns were match-cast in two pieces – some weighing almost 130,000 pounds – and assembled at the stadium.

A Minnesota-based company is nationally recognized as an expert in "Superpave" – high-quality, high rock-content asphalt paving projects. It also completed a large, two-year highway paving project in Minnesota that required 252,366 tons of aggregate, 130,914 tons of bituminous mix and 143,283 square yards of asphalt removal, which was turned into recycled asphalt product.

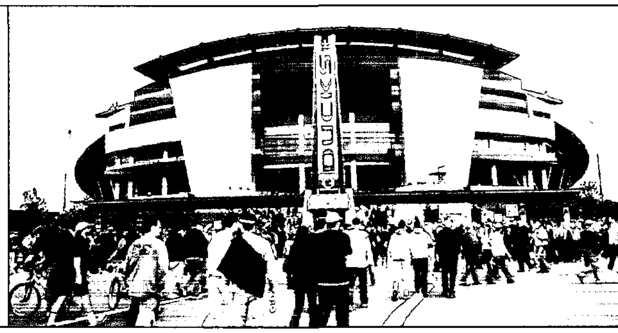
A broad range of expertise and capabilities throughout Knife River's companies makes it an aggressive player in the construction materials industry.

Maximizing synergies has been a focus of the Knife River companies. Coordinated purchasing of virtually all of the company's heavy equipment, vehicles, tires, parts and maintenance items has resulted in considerable cost savings. A corporate-wide financial reporting system is being installed to improve efficiencies in back office support.

Revenues have doubled since 1999

Ron Fruth of Granite City Ready-Mix, Inc. in St. Cloud, Minn., places a company logo on a new ready-mix truck. Granite City joined Knife River Corporation in 2002.

Morse Bros., Inc. created more than 1,380 pre-cast concrete components for the expansion of Autzen Stadium, home of the University of Oregon Ducks football team.



Employees are key to operations success. Knife River companies stress safety and customer service. The Mentor-Driver Program recognizes that the ready-mix truck driver is the primary contact with the customer and trains drivers to be good salespersons as well as construction materials service providers.

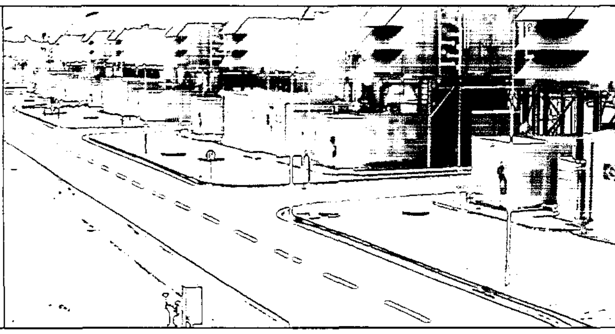
Challenges and opportunities

Consolidation trends in the construction materials industry should provide a continuing opportunity as well as a challenge for Knife River. The company plans to continue its focus of buying stable, well-managed companies at reasonable prices and to realize synergies as companies are rolled into the corporation. Challenges that Knife River faces continue to be those typical of this industry, such as weather, regional economic conditions, state infrastructure financing, and the potential for a general slowdown in road construction and homebuilding. These challenges are largely mitigated through regional diversity.

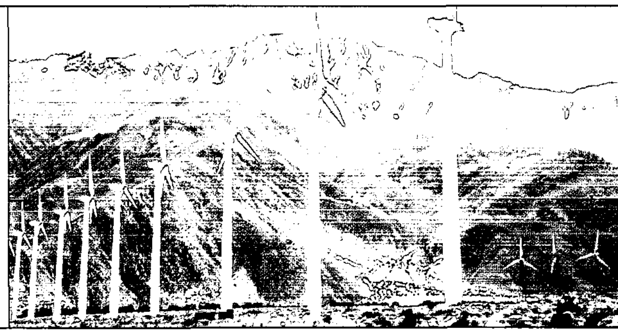
In an era when new permits are difficult to obtain, Knife River's primary competitive advantage is its more than 1 billion tons of strategically located permitted reserves. Mining an average of 30 million tons per year, represents a 30- to 40-year supply of construction materials that will build and maintain the nation's infrastructure. Building value from these hard assets will provide the foundation for solid shareholder returns for years to come.

Finding growth opportunities in meeting the Americas' energy needs

Independent power production through Centennial Energy Resources is the corporation's latest effort to build on its expertise. Changes in the electric business and growing demand for power have created a buyer's market for those who have been disciplined in waiting for the right opportunities. MDU Resources' strategies to concentrate on properties with long-term power and capacity contracts are proving successful in starting this new business segment.



△ This 200-megawatt natural gas-fired power plant built near Fortaleza, on the northeastern coast of Brazil, helps supply the fast-growing energy needs of South America.



△ The company recently purchased this 111-turbine wind facility located in California's San Gorgonio Pass, one of the nation's prime wind energy development areas.

Powerful partnering in Brazil

The company joined with a Brazilian partner to help supply electricity to the northeastern part of Brazil, which has had capacity shortages and rapidly growing demand. They forged a long-term sales agreement with Petrobras, one of the world's largest energy companies, for capacity – the ability to generate energy – along with a fuel supply agreement that matches the generating requirements of the contract. The company constructed a 200-megawatt, natural gas-fired power plant, which was placed into service as gas was made available. The first 100 megawatts went on line in mid-summer, with the second 100 megawatts placed in service in January 2003.

Energy to serve Colorado's growth

In November, the company purchased a 213-megawatt, natural gas-fired electric generating facility in Brush, Colorado. The facility supplies power to the Denver metropolitan area, one of the more rapidly growing markets in the United States. Ninety-five percent of the output of the facility is sold under contract.

Wind power for California markets

A long-term contract with the California Department of Water Resources for all the output of a 66.6-megawatt wind-powered electric generation facility was one of the key factors in diversifying generation assets into wind power. This facility was purchased in early 2003. A reliable earnings stream unaffected by economic cycles from an environmentally sound project was just what the company was looking for as it builds on its independent power production expertise.

Prior to the fourth quarter of 2002, MDU Resources Group, Inc. (Company) reported six business segments consisting of electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production and construction materials and mining. During the fourth quarter of 2002, the Company added an additional segment, independent power production, based on the significance of this segment's operations. Substantially all of the operations of the independent power production segment began in 2002, therefore financial information for years prior to 2002 has not been presented.

The Company's operations are now conducted through seven business segments. For purposes of segment financial reporting and discussion of results of operations, electric and natural gas distribution include the electric and natural gas distribution operations of Montana-Dakota Utilities Co. and the natural gas distribution operations of Great Plains Natural Gas Co. Utility services includes all the operations of Utility Services, Inc. Pipeline and energy services includes WBI Holdings, Inc.'s natural gas transportation, underground storage, gathering services, and energy related management services. Natural gas and oil production includes the natural gas and oil acquisition, exploration and production operations of WBI Holdings. Construction materials and mining includes the results of Knife River Corporation's operations, while independent power production includes electric generating facilities in the United States and Brazil and also invests in potential new growth and synergistic opportunities that are not directly being pursued by other business segments.

Reference should be made to Items 1 and 2 – Business and Properties, Item 3 – Legal Proceedings in the Company's 2002 Form 10-K and Notes to Consolidated Financial Statements for information pertinent to various commitments and contingencies.

Overview

The following table summarizes the contribution to consolidated earnings by each of the Company's business segments.

Years ended December 31,	2002	2001	2000
	(Dollars in millions, where applicable)		
Electric	$ 15.8	$ 18.7	$ 17.7
Natural gas distribution	3.6	.7	4.8
Utility services	6.4	12.9	8.6
Pipeline and energy services	19.1	16.4	10.5
Natural gas and oil production	53.2	63.2	38.6
Construction materials and mining	48.7	43.2	30.1
Independent power production	.9	–	–
Earnings on common stock	$147.7	$155.1	$110.3
Earnings per common share – basic	$ 2.09	$ 2.31	$ 1.80
Earnings per common share – diluted	$ 2.07	$ 2.29	$ 1.80
Return on average common equity	12.5%	15.3%	14.3%

2002 compared to 2001 Consolidated earnings for 2002 decreased $7.4 million from the comparable period a year ago due to lower earnings at the natural gas and oil production, utility services and electric businesses. Increased earnings at the construction materials and mining, natural gas distribution and pipeline and energy services businesses, along with earnings from the independent power production business, partially offset the earnings decline.

2001 compared to 2000 Consolidated earnings for 2001 increased $44.8 million from the comparable period a year ago due to higher earnings from the natural gas and oil production, construction materials and mining, pipeline and energy services, utility services and electric businesses. Lower earnings at the natural gas distribution business partially offset the earnings increase.

Financial and Operating Data

The following tables are key financial and operating statistics for each of the Company's business segments.

Electric

Years ended December 31,	2002	2001	2000
	(Dollars in millions, where applicable)		
Operating revenues:			
Retail sales	$142.1	$137.3	$134.5
Sales for resale and other	20.5	31.5	27.1
	162.6	168.8	161.6
Operating expenses:			
Fuel and purchased power	56.0	57.4	54.1
Operation and maintenance	46.0	45.6	42.5
Depreciation, depletion and amortization	19.6	19.5	19.1
Taxes, other than income	7.1	7.6	7.1
	128.7	130.1	122.8
Operating income	$ 33.9	$ 38.7	$ 38.8
Retail sales (million kWh)	2,275.0	2,177.9	2,161.3
Sales for resale (million kWh)	784.6	898.2	930.3
Average cost of fuel and purchased power per kWh	$ .018	$ .018	$ .016

2002 compared to 2001 Electric earnings decreased as a result of lower average realized sales for resale prices, which were 34 percent lower than last year, due to weaker demand in the sales for resale markets; the absence in 2002 of 2001 insurance recovery proceeds related to a 2000 outage at an electric generating station; and lower sales for resale volumes, which were 13 percent lower than last year. Partially offsetting the earnings decline were increased retail sales volumes, which were 4 percent higher than last year, primarily to residential, commercial and large industrial customers; decreased fuel and purchased power costs, largely lower demand charges resulting from the absence of a 2001 extended maintenance outage at an electric supplier's generating station; and increased retail sales prices, primarily demand revenue, which were partially offset by the North Dakota retail rate reduction. For further information on the North Dakota retail rate reduction, see Note 16 of Notes to Consolidated Financial Statements.

2001 compared to 2000 Electric earnings increased due to higher average realized sales for resale prices, decreased interest expense due to lower average borrowings, and insurance recovery proceeds related to a 2000 outage at an electric generating station. Higher operation and maintenance expense, primarily increased payroll expense and higher subcontractor costs, and increased fuel and purchased power costs, largely higher demand charge costs related to an extended maintenance outage at an electric power supplier's generating station, partially offset the earnings increase. Also partially offsetting the earnings increase were lower sales for resale volumes, and increased depreciation, depletion and amortization expense resulting from higher property, plant and equipment balances.

Natural Gas Distribution

Years ended December 31,	2002	2001	2000
	(Dollars in millions, where applicable)		
Operating revenues:			
Sales	$182.5	$251.3	$229.2
Transportation and other	4.1	4.1	3.9
	186.6	255.4	233.1
Operating expenses:			
Purchased natural gas sold	132.9	200.7	178.6
Operation and maintenance	36.5	36.6	32.0
Depreciation, depletion and amortization	9.9	9.4	8.4
Taxes, other than income	4.9	5.1	4.6
	184.2	251.8	223.6
Operating income	$ 2.4	$ 3.6	$ 9.5
Volumes (MMdk):			
Sales	39.6	36.5	36.6
Transportation	13.7	14.3	14.3
Total throughput	53.3	50.8	50.9
Degree days (% of normal)	101.1%	94.5%	100.4%
Average cost of natural gas, including transportation thereon, per dk	$ 3.22	$ 5.50	$ 4.88

2002 compared to 2001 Earnings at the natural gas distribution business increased as a result of higher retail sales volumes, which were 8 percent higher than last year, largely the result of weather that was 9 percent colder than the prior year; increased return on natural gas storage, demand and prepaid commodity balances; increased retail sales prices, largely the result of rate increases in Minnesota, Montana and North Dakota; higher service and repair margins; and lower income taxes, largely the result of the reversal of certain tax contingency reserves. A reserve adjustment of $3.3 million (after tax) related to certain pipeline capacity charges partially offset the earnings increase. The pass-through of lower natural gas prices resulted in the decrease in sales revenues and purchased natural gas sold. For further information on the retail rate increases, see Note 16 of Notes to Consolidated Financial Statements.

2001 compared to 2000 Earnings at the natural gas distribution business decreased as a result of lower sales volumes, largely the result of weather in the fourth quarter which was 22 percent warmer than a year ago, and higher operation and maintenance expenses, primarily increased payroll costs and higher bad debt expense. Lower average realized rates, return on natural gas storage, demand and prepaid commodity balances, and decreased service and repair margins also added to the earnings decline. Slightly offsetting the decline were decreased interest expense due to lower average borrowings, and earnings from a natural gas utility business acquired in July 2000. The pass-through of higher natural gas prices resulted in the increase in sales revenue and purchased natural gas sold.

Utility Services

Years ended December 31,	2002	2001	2000
	(Dollars in millions)		
Operating revenues	$458.7	$364.8	$169.4
Operating expenses:			
Operation and maintenance	419.0	321.0	142.6
Depreciation, depletion and amortization	9.9	8.4	4.9
Taxes, other than income	15.8	10.2	5.3
	444.7	339.6	152.8
Operating income	$ 14.0	$ 25.2	$ 16.6

2002 compared to 2001 Utility services earnings decreased as a result of lower line construction margins in the Rocky Mountain region related primarily to decreased fiber optic construction work; lower construction margins in the Central region due to decreased inside electrical work; the write-off of certain receivables and restructuring of the engineering function of approximately $5.2 million (after tax); and decreased equipment sales and margins. Partially offsetting the earnings decline were increased workloads in the Southwest and Northwest regions, the discontinuance of the amortization of goodwill in 2002 ($1.4 million after tax in 2001), and decreased interest expense, primarily due to lower debt balances. The increase in revenues and the related increase in operation and maintenance expense resulted largely from businesses acquired since the comparable period last year.

2001 compared to 2000 Utility services earnings increased as a result of earnings from businesses acquired since the comparable period last year, slightly higher operating margins from existing operations and decreased interest expense due to lower average interest rates. The earnings improvement was partially offset by higher selling, general and administrative costs.

Pipeline and Energy Services

Years ended December 31,	2002	2001	2000
	(Dollars in millions)		
Operating revenues:			
Pipeline	$ 95.3	$ 87.1	$ 77.4
Energy services	69.9	444.0	559.4
	165.2	531.1	636.8
Operating expenses:			
Purchased natural gas sold	58.3	433.5	548.3
Operation and maintenance	47.3	47.1	39.1
Depreciation, depletion and amortization	14.8	14.3	15.3
Taxes, other than income	5.7	5.8	5.3
	126.1	500.7	608.0
Operating income	$ 39.1	$ 30.4	$ 28.8
Transportation volumes (MMdk):			
Montana-Dakota	33.3	34.1	30.6
Other	66.6	63.1	56.2
	99.9	97.2	86.8
Gathering volumes (MMdk)	72.7	61.1	41.7

2002 compared to 2001 Earnings at the pipeline and energy services business increased as a result of higher gathering revenues, largely increased gathering volumes, which were 19 percent higher than last year, at higher average rates, and higher stand-by fees; increased volumes transported on-system and off-system, at slightly higher average rates; and higher storage revenues. Also contributing to the earnings improvement were lower corporate development costs and the absence in 2002 of a 2001 write-off of an investment in a software development company of $699,000 (after tax). Partially offsetting the earnings increase were the net effects of the sale of certain smaller nonstrategic properties in 2001 along with higher operation and maintenance expense and higher depreciation, depletion and amortization expense, a result of the gathering system expansion to accommodate increasing natural gas volumes. The $374.1 million decrease in energy services revenue and the related decrease in purchased natural gas sold were due primarily to decreased energy marketing volumes resulting from the sale of the vast majority of the Company's energy marketing operations in the third quarter of 2001.

2001 compared to 2000 Earnings at the pipeline and energy services business increased due to higher transportation and gathering volumes at higher average rates at the pipeline. The absence in 2001 of an asset impairment recognized in 2000 in the amount of $3.9 million after tax at one of the Company's energy services companies and the net effect of the sale in 2001 of certain smaller nonstrategic properties at the pipeline also added to the earnings increase. In addition, higher natural gas sales margins at energy services added to the earnings increase. Partially offsetting the earnings increase were the absence in 2001 of a 2000 $6.7 million after-tax reserve revenue adjustment and resulting increase to income relating to certain regulatory proceedings, prior to the proceeding filed in 1999, and higher operation and maintenance expense. The write-off of an investment in a software development company of $699,000 (after tax) and expenses incurred for corporate development costs also partially offset the earnings increase. The higher operation and maintenance expense was due primarily to increased compressor-related expenses in connection with the expansion of the gathering systems. The decrease in energy services revenue and the related decrease in purchased natural gas sold resulted from decreased energy marketing sales volumes at certain energy services operations that were sold in 2001.

Natural Gas and Oil Production

Years ended December 31,	2002	2001	2000
	(Dollars in millions, where applicable)		
Operating revenues:			
Natural gas	$131.1	$153.3	$ 84.7
Oil	44.9	50.2	43.4
Other	27.6*	6.3	10.2
	203.6	209.8	138.3
Operating expenses:			
Purchased natural gas sold	.1	2.8	3.4
Operation and maintenance	55.6	50.4	31.3
Depreciation, depletion and amortization	48.7	41.7	27.0
Taxes, other than income	13.6	11.0	10.1
	118.0	105.9	71.8
Operating income	$ 85.6	$103.9	$ 66.5
Production:			
Natural gas (MMcf)	48,239	40,591	29,222
Oil (000's of barrels)	1,968	2,042	1,882
Average realized prices:			
Natural gas (per Mcf)	$ 2.72	$ 3.78	$ 2.90
Oil (per barrel)	$22.80	$24.59	$23.06

**Includes the effects of a nonrecurring compromise agreement of $27.4 million ($16.6 million after tax) in the first quarter of 2002.*

2002 compared to 2001 Natural gas and oil production earnings decreased largely due to lower realized natural gas and oil prices, which were 28 percent and 7 percent lower than last year, respectively, along with lower oil production of 4 percent; partially offset by higher natural gas production of 19 percent, largely from operated properties in the Rocky Mountain area. Also adding to the earnings decline were increased depreciation, depletion and amortization expense due to higher natural gas production volumes and higher rates; increased operation and maintenance expense, mainly higher lease operating expenses resulting from the expansion of coalbed natural gas production; and lower sales volumes of inventoried natural gas. Partially offsetting the earnings decline were the effects of the nonrecurring compromise agreement of $27.4 million ($16.6 million after tax), included in operating revenues, as discussed in Note 17 of Notes to Consolidated Financial Statements. Hedging activities for natural gas and oil production for 2002 resulted in realized prices that were 107 percent and 98 percent, respectively, of what otherwise would have been received.

2001 compared to 2000 Natural gas and oil production earnings increased largely due to higher natural gas and oil production of 39 percent and 9 percent since last year, respectively, combined with increased realized natural gas and oil prices, which were 30 percent and 7 percent higher than last year, respectively. The higher production was largely the result of a natural gas property acquisition in April 2000 and the ongoing development of that property as well as existing properties. Also adding to the earnings increase was lower interest expense, a result of lower debt balances combined with lower average rates. Partially offsetting the earnings improvement were increased operation and maintenance expense, mainly higher lease operating expenses and higher general and administrative costs. Increased depreciation, depletion and amortization expense due to higher production volumes and higher rates, and lower sales volumes of inventoried natural gas also partially offset the earnings increase. Hedging activities for natural gas and oil production for 2001 resulted in realized prices that were 101 percent and 104 percent, respectively, of what otherwise would have been received.

Construction Materials and Mining

Years ended December 31,	2002	2001	2000
	(Dollars in millions)		
Operating revenues:			
Construction materials	$962.3	$794.6	$597.7
Coal	–*	12.3*	33.7
	962.3	806.9	631.4
Operating expenses:			
Operation and maintenance	797.7	673.1	526.0
Depreciation, depletion and amortization	54.4	46.6	36.2
Taxes, other than income	18.8	15.7	12.4
	870.9	735.4	574.6
Operating income	$ 91.4	$ 71.5	$ 56.8
Sales (000's):			
Aggregates (tons)	35,078	27,565	18,315
Asphalt (tons)	7,272	6,228	3,310
Ready-mixed concrete (cubic yards)	2,902	2,542	1,696
Coal (tons)	–*	1,171*	3,111

**Coal operations were sold effective April 30, 2001.*

2002 compared to 2001 Earnings for the construction materials and mining business increased as a result of earnings from businesses acquired since the comparable period last year; higher aggregate, asphalt and cement sales volumes; increased construction revenues, largely the result of several large projects mainly in California and Oregon; and lower asphalt costs. Partially offsetting the increase in earnings were the one-time gain in 2001 from the sale of the Company's coal operations of $10.3 million ($6.2 million after tax, including final settlement cost adjustments), included in other income – net, as discussed in Note 12 of Notes to Consolidated Financial Statements, as well as earnings from four months of coal operations included in 2001 earnings. Higher selling, general and administrative costs, mainly due to higher computer support, insurance and payroll costs; and higher depreciation, depletion and amortization expense due to higher sales volumes, partially offset by the discontinuance of the amortization of goodwill in 2002 ($1.7 million after tax in 2001), also added to the partial offset in earnings.

2001 compared to 2000 Earnings for the construction materials and mining business increased largely due to earnings from businesses acquired since the comparable period last year and increases at existing asphalt, aggregate, cement and ready-mixed concrete construction materials operations. Also adding to the earnings increase was a one-time gain from the sale of the coal operations of $10.3 million ($6.2 million after tax, including final settlement cost adjustments), included in other income – net, as discussed in Note 12 of Notes to Consolidated Financial Statements, partially offset by lower coal sales volumes due primarily to four months of operations in 2001 compared to 12 months in 2000. Also partially offsetting the earnings increase were lower construction margins, largely resulting from increased competition and less available work, and the absence in 2001 of a 2000 gain of $1.2 million after tax on the sale of a nonstrategic property. Increased interest expense due to higher acquisition-related borrowings; higher depreciation, depletion and amortization expense due to increased plant balances; and higher selling, general and administrative costs also partially offset the earnings improvement.

Independent Power Production

Years ended December 31,	2002**	2001	2000
	(Dollars in millions)		
Operating revenues	$6.8	$ –	$ –
Operating expenses:			
Operation and maintenance	6.4	–	–
Depreciation, depletion and amortization	.7	–	–
	7.1	–	–
Operating loss	$ (.3)	$ –	$ –
Electricity produced and sold (million kWh)	15.8	–	–

***Reflects international operations for 2002 and domestic operations acquired in November 2002. The earnings from the Company's equity method investment in Brazil were included in other income – net.*

2002 compared to 2001 Earnings at the independent power production segment totaled $959,000. The majority of these earnings came from the newly acquired 213-megawatt natural gas-fired electric generating facilities in Colorado. The Brazilian operations also contributed to earnings. The Company's 49 percent share of the gain of $13.6 million (after tax) from an embedded derivative in the electric power contract and margins at the Brazil facilities were largely offset by the Company's 49 percent share of the foreign currency losses of $9.4 million (after tax) resulting from devaluation of the Brazilian real and net interest expense of $3.6 million (after tax).

Amounts presented in the preceding tables for operating revenues, purchased natural gas sold and operation and maintenance expense will not agree with the Consolidated Statements of Income due to the elimination of intercompany transactions between the pipeline and energy services segment and the natural gas distribution, utility services, construction materials and mining, natural gas and oil production and independent power production segments. The amounts relating to the elimination of intercompany transactions for operating revenues, purchased natural gas sold, and operation and maintenance expense are as follows: $114.3 million, $98.8 million and $15.5 million for 2002; $113.2 million, $107.7 million and $5.5 million for 2001; and $96.9 million, $96.0 million and $.9 million for 2000, respectively.

Risk Factors and Cautionary Statements that May Affect Future Results

The Company is including the following factors and cautionary statements in this Annual Report to make applicable and to 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, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that 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, including statements contained within Prospective Information. 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 factors and cautionary statements.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. 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 the Company's expectations, beliefs or projections will be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which such statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which such statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of such factors, nor can it assess the effect of each such factor on the Company's business or the extent to which any such factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement.

Following are some specific factors that should be considered for a better understanding of the Company's financial condition. These factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

The recent events leading to the current adverse economic environment may have a general negative impact on the Company's future revenues.

In response to the occurrence of several recent events, including the September 11, 2001, terrorist attack on the United States, the ongoing war against terrorism by the United States and the bankruptcy of several large energy and telecommunications companies, the financial markets have been disrupted. An adverse economy could negatively affect the level of governmental expenditures on public projects and the timing of these projects that, in turn, would negatively affect the demand for the Company's products and services.

Innovatum, Inc. (Innovatum), an indirect wholly owned subsidiary of the Company specializing in cable and pipeline magnetization and locating, is subject to the economic conditions within the telecommunications and energy industries. Innovatum could face a future goodwill impairment if there is a continued downturn in these sectors. At December 31, 2002, the goodwill amount at Innovatum was approximately $8.3 million. The determination of whether an impairment will occur is dependent on a number of factors, including the level of spending in the telecommunications and energy industries, the rapid changes in technology, competitors and potential new customers.

The Company's natural gas and oil production business is dependent on factors including commodity prices that cannot be predicted or controlled.

These factors include price fluctuations in natural gas and crude oil prices; availability of economic supplies of natural gas; drilling successes in natural gas and oil operations; the ability to contract for or to secure necessary drilling rig contracts and to retain employees to drill for and develop reserves; the ability to acquire natural gas and oil properties; and other risks incidental to the operations of natural gas and oil wells.

The Company's operations are weather sensitive.

The Company's results of operations can be affected by changes in the weather. Weather conditions directly influence the demand for electricity and natural gas, affect the price of energy commodities and affect the ability to perform services at the utility services and construction materials and mining businesses. The Company cannot predict future weather conditions and as a result, adverse weather conditions could negatively affect the Company's operations and financial conditions.

The Company is subject to extensive environmental laws and regulations that may increase its costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.
The Company is subject to extensive environmental laws and regulations affecting many aspects of its present and future operations including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating, and other costs, as a result of compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions and coalbed natural gas development. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. The Company cannot predict the outcome (financial or operational) of any related litigation that may arise.

There are no assurances that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to the Company. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on the Company's results of operations.

Fidelity has been named as a defendant in several lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming. Fidelity believes the ultimate outcome of these actions would not have a material effect on its existing coalbed natural gas operations. However, if the plaintiffs are successful, which Fidelity does not currently anticipate, the ultimate outcome of the actions could have a material effect on Fidelity's future development of its coalbed natural gas properties.

The Company is subject to extensive government regulations that may have a negative impact on its business and its results of operations.
The Company is subject to regulation by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return, financings, industry rate structures, recovery of purchased power and purchased gas costs. These governmental regulations significantly influence the Company's operating environment and may affect its ability to recover costs from its customers. The Company is required to have numerous permits, approvals and certificates from the agencies that regulate its business. The Company believes the necessary permits, approvals and certificates have been obtained for existing operations and that the Company's business is conducted in accordance with applicable laws; however, the Company is unable to predict the impact on operating results from the future regulatory activities of any of these agencies.

Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company's results of operations.

The Company is dependent on its ability to successfully access capital markets. Inability to access capital may limit its ability to execute business plans, pursue improvements or make acquisitions that it may otherwise rely on for future growth.
The Company relies on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as a significant source of liquidity for capital requirements not satisfied by the cash flow from its operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions or a downgrade of its credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- A severe economic downturn
- The bankruptcy of unrelated companies in the same line of business
- Capital market conditions generally
- Commodity prices
- Terrorist attacks
- Global events

There are risks involved with the growth strategies of the Company's independent power production business.
The operation of power generation facilities involves many risks, including start up risks, breakdown or failure of equipment, competition, inability to obtain required governmental permits and approvals and inability to negotiate acceptable acquisition, construction, fuel supply or other material agreements, as well as the risk of performance below expected levels of output or efficiency.

The Company's plans to construct a 113-megawatt coal-fired electric generation station in Montana are pending. The Company purchased plant equipment and obtained all permits necessary to begin construction. NorthWestern Energy terminated the power purchase agreement for the energy from this plant in July 2002; however, the Company is pursuing other markets for the energy and is studying its options regarding this project. The Company has suspended construction activities except for those items of a critical nature. At December 31, 2002, the Company's investment in this project was approximately $23.1 million. If it is not economically feasible for the Company to construct and operate this facility or if alternate markets cannot be identified, an asset impairment may occur.

The value of the Company's investment in foreign operations may diminish due to political, regulatory and economic conditions and changes in currency rates in countries where the Company does business.
The Company is subject to political, regulatory and economic conditions and changes in currency rates in foreign countries where the Company does business. Significant changes in the political, regulatory or economic environment in these countries could negatively affect the value of the Company's investments located in these countries. Also, since the Company is unable to predict the fluctuations in the foreign currency exchange rates, these fluctuations may have an adverse impact on the Company's results of operations.

The Company's 49 percent equity method investment in a 200-megawatt natural gas-fired electric generation project in Brazil includes a power purchase agreement that contains an embedded derivative. This embedded derivative derives its value from an annual adjustment factor that largely indexes the contract capacity payments to the U.S. dollar. In addition, from time to time, other derivative instruments may be utilized. The valuation of these financial instruments, including the embedded derivative, can involve judgments, uncertainties and the use of estimates. As a result, changes in the underlying assumptions could affect the reported fair value of these instruments. These instruments could recognize financial losses as a result of volatility in the underlying fair values, or if a counterparty fails to perform.

Competition is increasing in all of the Company's businesses.
All of the Company's business segments are subject to increased competition. The independent power industry includes numerous strong and capable competitors, many of which have extensive experience in the operation, acquisition and development of power generation facilities. Utility services' competition is based primarily on price and reputation for quality, safety and reliability. The construction materials products are marketed under highly competitive conditions and are subject to such competitive forces as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries are also experiencing increased competitive pressures as a result of consumer demands, technological advances, deregulation, greater availability of natural gas-fired generation and other factors. Pipeline and energy services competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The natural gas and oil production business is subject to competition in the acquisition and development of natural gas and oil properties.

Other important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in forward-looking statements include:

- Acquisition and disposal of assets or facilities
- Changes in operation and construction of plant facilities
- Changes in present or prospective generation
- Changes in anticipated tourism levels
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for energy from plants or facilities
- Changes in tax rates or policies
- Unanticipated project delays or changes in project costs
- Unanticipated changes in operating expenses or capital expenditures
- Labor negotiations or disputes
- Inflation rates
- Inability of the various counterparties to meet their contractual obligations
- Changes in accounting principles and/or the application of such principles to the Company
- Changes in technology and legal proceedings
- The ability to effectively integrate the operations of acquired companies

Prospective Information

The following information includes highlights of the key growth strategies, projections and certain assumptions for the Company and its subsidiaries over the next few years and other matters for each of the Company's seven business segments. Many of these highlighted points are forward-looking statements. There is no assurance that the Company's projections, including estimates for growth and increases in revenues and earnings, will in fact be achieved. Reference should be made to assumptions contained in this section as well as the various important factors listed under the heading Risk Factors and Cautionary Statements that May Affect Future Results. Changes in such assumptions and factors could cause actual future results to differ materially from targeted growth, revenue and earnings projections.

MDU Resources Group, Inc.

- 2003 earnings per share, diluted, before the cumulative effect of an accounting change required by the implementation of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143) in the first quarter of 2003, are projected in the range of $1.80 to $2.05.

- The Company expects the percentage of 2003 earnings per share before the cumulative effect of an accounting change by quarter to be in the following approximate ranges:
  - First Quarter: 5 percent to 10 percent
  - Second Quarter: 20 percent to 25 percent
  - Third Quarter: 40 percent to 45 percent
  - Fourth Quarter: 25 percent to 30 percent

- The Company will examine issuing equity from time to time to keep debt at the nonregulated businesses at no more than 40 percent of total capitalization.

- The Company's long-term compound annual growth goals on earnings per share from operations are in the range of 6 percent to 9 percent.

Electric

- Montana-Dakota has obtained and holds valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. As franchises expire, Montana-Dakota may face increasing competition in its service areas, particularly its service to smaller towns, from rural electric cooperatives. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises and will continue to take steps to effectively operate in an increasingly competitive environment.

- A 40-megawatt natural gas-fired peaking unit is scheduled to be constructed for operation by June 1, 2003. This project is expected to be recovered in rates and will be used to meet the utility's need for additional generating capacity.

- Pending regulatory approval, Montana-Dakota plans to purchase energy from a 20-megawatt wind energy farm in North Dakota. Rate recovery is expected.

- Montana-Dakota is working with the state of North Dakota to determine the feasibility of constructing a 500-megawatt lignite-fired power plant in western North Dakota. In December 2002, Montana-Dakota confirmed its intent to continue the study, however, Montana-Dakota is also in the process of obtaining approval to include a 250-megawatt plant option within the study. The next preliminary decision is expected in late 2003.

Natural gas distribution

- Montana-Dakota and Great Plains have obtained and hold valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. As franchises expire, Montana-Dakota and Great Plains may face increasing competition in their service areas. Montana-Dakota and Great Plains intend to protect their service areas and seek renewal of all expiring franchises and will continue to take steps to effectively operate in an increasingly competitive environment.

- Annual natural gas throughput for 2003 is expected to be approximately 50 million decatherms.

- Montana-Dakota or Great Plains have filed applications with state regulatory authorities in three states (Minnesota, Montana and South Dakota) seeking increases in natural gas retail rates that are in the range of 5.8 percent to 6.9 percent above current rates. While Montana-Dakota and Great Plains believe that they should be authorized to increase retail rates in the respective amounts requested, there is no assurance that the increases ultimately allowed will be for the full amounts requested in each jurisdiction. For further information on the natural gas rate increase applications, see Note 16 of Notes to Consolidated Financial Statements.

Utility services

- Revenues for this segment are expected to be in the range of $450 million to $500 million in 2003. This segment anticipates margins in 2003 to increase over 2002 levels.

Pipeline and energy services

- In 2003, natural gas throughput from this segment, including both transportation and gathering, is expected to increase slightly over the 2002 record level throughput.

- A 247-mile pipeline to transport additional natural gas to market and enhance the use of this segment's storage facilities is currently under regulatory review. Depending upon the timing of receiving the necessary regulatory approval, completion of construction could occur in late 2003.

- Innovatum could face a future goodwill impairment based on certain economic conditions, as previously discussed in Risk Factors and Cautionary Statements that May Affect Future Results.

Natural gas and oil production

- In 2003, this segment expects a combined natural gas and oil production increase in excess of 20 percent over 2002 record levels.

- This segment expects to drill in excess of 400 wells in 2003.

- This segment had approximately 300 wells related to its coalbed natural gas development in the Powder River Basin in Montana and Wyoming that were not producing natural gas at December 31, 2002. A large number of these wells are expected to begin producing natural gas in 2003.

- Natural gas prices in the Rocky Mountain region for February through December 2003 reflected in the Company's 2003 earnings guidance are in the range of $2.50 to $3.00 per Mcf. The Company's estimates for natural gas prices on the NYMEX for February through December 2003 reflected in the Company's 2003 earnings guidance are in the range of $3.00 to $3.50 per Mcf. During 2002, more than half of this segment's natural gas production was priced using Rocky Mountain or other non-NYMEX prices.
- NYMEX crude oil prices for January through December 2003 reflected in the Company's 2003 earnings guidance are in the range of $20 to $25 per barrel.
- This segment has hedged a portion of its 2003 production primarily using collars that establish both a floor and a cap. The Company has entered into agreements representing approximately 40 percent to 45 percent of 2003 estimated annual natural gas production. The agreements are at various indices and range from a low CIG index of $2.94 to a high Ventura index of $4.76 per Mcf.
- The Company has hedged a portion of its 2003 oil production. The Company has entered into agreements at NYMEX prices with floors of $24.50 and caps as high as $28.12 per barrel, representing approximately 30 percent to 35 percent of 2003 estimated annual oil production.
- Fidelity has been named as a defendant in several lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming, as previously discussed in Risk Factors and Cautionary Statements that May Affect Future Results.

Construction materials and mining

- Excluding the effects of potential future acquisitions, aggregate, asphalt and ready-mixed concrete volumes are expected to remain at or near the record levels achieved in 2002.
- Revenues for this segment in 2003 are expected to be unchanged from 2002 record levels.

Independent power production

- Earnings projections for 2003 for the independent power production segment include the estimated results from the previously mentioned wind-powered electric generation facility and the 2002 acquisition of generating facilities in Colorado, as well as earnings from the 200-megawatt natural gas-fired generation project in Brazil. Earnings from this segment are expected to be in the range of $12 million to $17 million in 2003.
- On January 31, 2003, this segment purchased a 66.6-megawatt Mountain View wind-powered electric generating facility. The project sells all of its output under a long-term contract with the California Department of Water Resources.
- The Company's plans to construct a 113-megawatt coal-fired electric generation station in Montana are pending as previously discussed in Risk Factors and Cautionary Statements that May Affect Future Results.

New Accounting Standards

In June 2001, the Financial Accounting Standards Board (FASB) approved SFAS No. 143. The adoption of SFAS No. 143 is expected to result in a one-time cumulative effect after-tax charge to earnings in the range of $7.0 million to $10.0 million and is also estimated to reduce 2003 earnings before the cumulative effect charge by approximately $1.6 million to $2.1 million. In addition, a regulatory asset that is approximated to be less than $1.0 million will be recognized for the transition amount that is expected to be recovered in rates over time. The Company intends to record the cumulative charge and regulatory asset in the first quarter of 2003.

In April 2002, the FASB approved Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS No. 145). The Company believes the adoption of SFAS No. 145 will not have a material effect on its financial position or results of operations.

In June 2002, the FASB approved Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS No. 146). SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002, and is not expected to have a material effect on the Company's financial position or results of operations.

In September 2002, the Emerging Issues Task Force (EITF) issued consensus in EITF Issue No. 02-13, "Deferred Income Tax Considerations in Applying the Goodwill Impairment Test in FASB Statement No. 142, Goodwill and Other Intangible Assets" (EITF No. 02-13). EITF No. 02-13 did not have a material effect on the Company's goodwill impairment testing.

In October 2002, the EITF issued consensus in EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 02-3). The adoption of EITF No. 02-3 did not have a material effect on the Company's financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (Interpretation No. 45). The Company will apply the initial recognition and initial measurement provisions of Interpretation No. 45 to guarantees issued or modified after December 31, 2002.

In December 2002, the FASB approved Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123" (SFAS No. 148). The Company had adopted the disclosure provisions of SFAS No. 148 at December 31, 2002.

For further information on SFAS No. 143, SFAS No. 145, SFAS No. 146, EITF No. 02-13, EITF No. 02-3, Interpretation No. 45 and SFAS No. 148, see Note 1 of Notes to Consolidated Financial Statements.

Critical Accounting Policies

The Company has prepared its financial statements in conformity with accounting principles generally accepted in the United States of America, and these statements necessarily include some amounts that are based on informed judgments and estimates of management. The Company's significant accounting policies are discussed in Note 1 of Notes to Consolidated Financial Statements. The Company's critical accounting policies are subject to judgments and uncertainties which affect the application of such policies. As discussed below the Company's financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of such policies. In the event estimates or assumptions prove to be different from actual amounts, adjustments are made in subsequent periods to reflect more current information. The Company's critical accounting policies include:

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets, including goodwill and identifiable intangibles, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and annually for goodwill as required by Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangibles." Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties and may be estimated using a number of techniques, including quoted market prices or valuations by third parties, present value techniques based on estimates of cash flows, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Impairment testing of natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities as discussed in Note 1 of Notes to Consolidated Financial Statements. The full-cost method of accounting requires judgments and assumptions to be made when estimating and valuing reserves using specific point in time natural gas and oil prices. Sustained downward movements in natural gas and oil prices and changes in estimates of reserve quantities could result in a future write-down of the Company's natural gas and oil properties.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is probable. The Company's revenue recognition policy is discussed in Note 1 of Notes to Consolidated Financial Statements. The recognition of revenue in conformity with accounting principles generally accepted in the United States of America requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Estimates related to the recognition of revenue include the accumulated provision for revenues subject to refund, natural gas and oil revenues and costs on construction contracts under the percentage-of-completion method. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Derivatives

Certain subsidiaries of the Company have cash flow hedging instruments comprised of natural gas price swap and natural gas and oil collar agreements and a foreign currency collar agreement that has not been designated as a hedge. The fair values of the natural gas price swap and natural gas and oil collar agreements and the foreign currency collar agreement have been recorded on the Company's balance sheet. The objective for holding the natural gas price swap and natural gas and oil collar agreements is to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on the Company's forecasted sale of natural gas and oil production. The objective for holding the foreign currency collar agreement is to manage a portion of the Company's foreign currency risk. For more information on the Company's derivative instruments, see Note 5 of Notes to Consolidated Financial Statements. Material changes to the Company's results of operations could occur if the hedging instrument is not highly effective in achieving offsetting cash flows attributable to the hedged risk or due to fluctuations in foreign currency exchange rates. The fair value of the derivative instruments is based on valuations determined by the counterparties. Changes in counterparty valuation assumptions and estimates could cause a material effect on the Company's financial position or results of operations.

Purchase accounting

The Company accounts for its acquisitions under the purchase method of accounting and accordingly, the acquired assets and liabilities assumed are recorded at their respective fair values. The recorded values of assets and liabilities are based on third-party estimates and valuations when available. The remaining values are based on management's judgments and estimates, and accordingly, the Company's financial position or results of operations may be affected by changes in estimates and judgments.

Accounting for the effects of regulation

Substantially all of the Company's regulatory assets, other than certain deferred income taxes, are being reflected in rates charged to customers in accordance with Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Regulation" (SFAS No. 71). If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs. Consequently, the discontinuance of SFAS No. 71 could have a material effect on the Company's results of operations.

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company 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. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; the valuation of stock-based compensation; and the fair value of an embedded derivative in a power purchase agreement related to an equity method investment in Brazil as discussed in Note 2 of Notes to Consolidated Financial Statements. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Liquidity and Capital Commitments

Cash flows

Operating activities Cash flows provided by operating activities in 2002 decreased $22.2 million compared to 2001, largely the result of a decrease in cash from working capital items of $58.4 million. Higher depreciation, depletion and amortization expense of $18.0 million, resulting largely from increased property, plant and equipment balances, along with an increase in other noncurrent changes of $15.7 million partially offset the decrease in cash flows from operating activities.

In 2001, cash flows from operating activities increased $141.6 million compared to 2000, primarily due to an increase in net income of $44.8 million, and higher depreciation, depletion and amortization expense of $29.0 million, largely the result of increased acquisition-related property, plant and equipment balances. Also adding to the increase in operating cash flows was the increase in cash from changes in working capital items of $95.9 million.

Investing activities Cash flows used in investing activities in 2002 increased $6.2 million compared to 2001, the result of an increase in net capital expenditures (capital expenditures, acquisitions, net of cash acquired, and net proceeds from the sale or disposition of property) of $22.6 million and an increase in investments of $7.4 million, partially offset by a decrease in notes receivable of $23.8 million. Net capital expenditures exclude the noncash transactions related to acquisitions, including the issuance of the Company's equity securities. The noncash transactions were $47.2 million and $57.4 million for the years ended December 31, 2002 and 2001, respectively.

In 2001, cash flows used in investing activities decreased $49.0 million compared to 2000, primarily the result of a decrease in net capital expenditures of $67.2 million, partially offset by an increase in notes receivable of $18.8 million. Net capital expenditures exclude the following noncash transactions related to acquisitions: issuance of the Company's equity securities in 2001 and 2000 and the conversion of a note receivable to purchase consideration in 2000.

Financing activities Cash flows provided by financing activities in 2002 increased $48.8 million compared to 2001, primarily the result of the decrease of the repayment of long-term debt of $32.5 million and the net increase of short-term borrowings of $28.0 million, partially offset by the decrease in proceeds from issuance of common stock of $12.0 million.

In 2001, financing activities resulted in a decrease in cash flows of $144.3 million compared to 2000. This decrease was largely due to the increase of the repayment of long-term debt of $85.7 million, and the decrease of the issuance of long-term debt of $69.9 million. Partially offsetting the decrease was an increase in proceeds from issuance of common stock of $19.9 million.

Defined benefit pension plans

The Company has qualified noncontributory defined benefit pension plans (Pension Plans). Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the Pension Plans. Actuarial assumptions include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by the Company within certain guidelines. During the year ended December 31, 2002, the market value of plan assets was negatively affected by persistent declines in the equity markets. At December 31, 2002, certain noncontributory defined benefit pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $4.9 million. Pretax pension income reflected in the years ended December 31, 2002, 2001 and 2000, was $2.4 million, $4.4 million and $4.4 million, respectively. The change in pension income for the year ended December 31, 2003, is not expected to significantly affect earnings as a result of the impact of recent declines in the market value of Pension Plan assets. For further information on the Company's Pension Plans, see Note 14 of Notes to Consolidated Financial Statements.

Capital expenditures

The Company's capital expenditures for 2000 through 2002 and as anticipated for 2003 through 2005 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt and preferred stock.

	Actual			Estimated*		
	2000	2001	2002	2003	2004	2005
	(In millions)					
Capital expenditures:						
Electric	$ 15.8	$ 14.4	$ 27.8	$ 32.7	$ 21.5	$ 26.8
Natural gas distribution	21.3	14.7	11.0	15.2	13.0	12.8
Utility services	42.6	70.2	17.3	10.5	10.4	11.2
Pipeline and energy services	69.0	51.0	21.5	72.5	21.9	19.2
Natural gas and oil production	173.5	118.7	136.4	123.0	112.1	107.1
Construction materials and mining	218.7	170.6	106.9	48.6	52.9	49.1
Independent power production	–	–	95.7	166.1	1.1	1.1
	540.9	439.6	416.6	468.6	232.9	227.3
Net proceeds from sale or disposition of property	(11.0)	(51.6)	(16.2)	(4.9)	(.8)	(1.1)
Net capital expenditures	529.9	388.0	400.4	463.7	232.1	226.2
Retirement of long-term debt and preferred stock	29.4	115.2	82.6	22.2	173.9	70.4
	$559.3	$503.2	$483.0	$485.9	$406.0	$296.6

**The estimated 2003 through 2005 capital expenditures reflected in the above table exclude potential future acquisitions other than the previously disclosed purchase of a 66.6-megawatt wind-powered electric generation facility. The Company continues to evaluate potential future acquisitions; however, these acquisitions are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the above estimates.*

Capital expenditures for 2002, 2001 and 2000, related to acquisitions, in the preceding table include the following noncash transactions: issuance of the Company's equity securities of $47.2 million in 2002; issuance of the Company's equity securities of $57.4 million in 2001; and issuance of the Company's equity securities and the conversion of a note receivable to purchase consideration of $132.1 million in 2000.

In 2002, the Company acquired a number of businesses, none of which was individually material, including utility services companies in California and Ohio, construction materials and mining businesses in Minnesota and Montana, an energy development company in Montana and natural gas-fired electric generation facilities in Colorado. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $139.8 million.

The 2002 capital expenditures, including those for the previously mentioned acquisitions, and retirements of long-term debt and preferred stock, were met from internal sources, the issuance of long-term debt and the Company's equity securities. Capital expenditures for the years 2003 through 2005 include those for system upgrades, including a 40-megawatt natural gas-fired peaking unit, as previously discussed; routine replacements; service extensions; routine equipment maintenance and replacements; land and building improvements; pipeline and gathering expansion projects, including a 247-mile pipeline, as previously discussed; the further enhancement of natural gas and oil production and reserve growth; power generation opportunities, including the acquisition of a 66.6-megawatt wind-powered electric generation facility and construction of a 113-megawatt coal-fired electric generation station, both as previously discussed; and for other growth opportunities. The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures and retirements of long-term debt and preferred stock for the years 2003 through 2005 will be met from various sources. These sources include internally generated funds, commercial paper credit facilities at Centennial Energy Holdings, Inc. (Centennial), a wholly owned subsidiary of the Company, and MDU Resources Group, Inc., as described below, and through the issuance of long-term debt and the Company's equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2002.

MDU Resources Group, Inc. The Company has unsecured short-term bank lines of credit from several banks totaling $46 million and a revolving credit agreement with various banks totaling $50 million at December 31, 2002. The bank lines of credit provide for commitment fees at varying rates and there were no amounts outstanding under the bank lines of credit or the credit agreement at December 31, 2002. The bank lines of credit and the credit agreement support the Company's $75 million commercial paper program. Under the Company's commercial paper program, $58.0 million was outstanding at December 31, 2002, of which $8.0 million was classified as short-term borrowings and $50.0 million was classified as long-term debt. The commercial paper borrowings classified as short term are supported by the short-term bank lines of credit. The commercial paper borrowings classified as long-term debt are intended to be refinanced on a long-term basis through continued Company commercial paper borrowings supported by the credit agreement, which allows for subsequent borrowings up to a term of one year. The Company intends to renew or replace the existing credit agreement, which expires December 30, 2003.

The Company's goal is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. If the Company were to experience a minor downgrade of its credit rating, it would not anticipate any change in its ability to access the capital markets. However, in such event, the Company would expect a nominal basis point increase in overall interest rates with respect to its cost of borrowings. If the Company were to experience a significant downgrade of its credit ratings, which it does not currently anticipate, it may need to borrow under its credit agreement and/or bank lines of credit.

To the extent the Company needs to borrow under its credit agreement and/or its bank lines of credit, it would be expected to incur increased annualized interest expense on its variable rate debt of approximately $87,000 (after tax) based on December 31, 2002, variable rate borrowings. Based on the Company's overall interest rate exposure at December 31, 2002, this change would not have a material effect on the Company's results of operations or cash flows.

On an annual basis, the Company negotiates the placement of its credit agreement and bank lines of credit that provide credit support to access the capital markets. In the event the Company was unable to successfully negotiate the credit agreement and/or the bank lines of credit, or in the event the fees on such facilities became too expensive, which it does not currently anticipate, the Company would seek alternative funding. One source of alternative funding might involve the securitization of certain Company assets.

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum leverage ratios, minimum interest coverage ratio, limitation on sale of assets and limitation on investments. The Company was in compliance with these covenants and met the required conditions at December 31, 2002. In the event the Company does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued as previously described.

Currently, there are no credit facilities that contain cross-default provisions between the Company and any of its subsidiaries.

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Indenture of Mortgage. Generally, those restrictions require the Company to pledge $1.43 of unfunded property to the trustee for each dollar of indebtedness incurred under the Indenture and that annual earnings (pretax and before interest charges), as defined in the Indenture, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the two tests, as of December 31, 2002, the Company could have issued approximately $327 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 4.8 times and 5.3 times for the years ended December 31, 2002 and 2001, respectively. Additionally, the Company's first mortgage bond interest coverage was 7.7 times and 8.5 times for the years ended December 31, 2002 and 2001, respectively. Common stockholders' equity as a percent of total capitalization was 60 percent and 58 percent at December 31, 2002 and 2001, respectively.

Centennial Energy Holdings, Inc. Centennial has a revolving credit agreement with various banks that supports $305 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreement at December 31, 2002. Under the Centennial commercial paper program, $101.9 million was outstanding at December 31, 2002. The Centennial commercial paper borrowings are classified as long term as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings and as further supported by the Centennial credit agreement, which allows for subsequent borrowings up to a term of one year. Centennial intends to renew the Centennial credit agreement, which expires September 26, 2003.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $400 million. Under the terms of the master shelf agreement, $360.6 million was outstanding at December 31, 2002. On January 17, 2003, Centennial borrowed an additional $39.0 million under the terms of this agreement. The $39.0 million in proceeds was used to pay down Centennial commercial paper program borrowings. In the future, Centennial intends to pursue other financing arrangements, including private and/or public financing.

Centennial's goal is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. If Centennial were to experience a minor downgrade of its credit rating, it would not anticipate any change in its ability to access the capital markets. However, in such event, Centennial would expect a nominal basis point increase in overall interest rates with respect to its cost of borrowings. If Centennial were to experience a significant downgrade of its credit ratings, which it does not currently anticipate, it may need to borrow under its committed bank lines.

To the extent Centennial needs to borrow under its committed bank lines, it would be expected to incur increased annualized interest expense on its variable rate debt of approximately $153,000 (after tax) based on December 31, 2002, variable rate borrowings. Based on Centennial's overall interest rate exposure at December 31, 2002, this change would not have a material effect on the Company's results of operations or cash flows.

On an annual basis, Centennial negotiates the placement of the Centennial credit agreement that provides credit support to access the capital markets. In the event Centennial was unable to successfully negotiate the credit agreement, or in the event the fees on such facility became too expensive, which Centennial does not currently anticipate, it would seek alternative funding. One source of alternative funding might involve the securitization of certain Centennial assets.

In order to borrow under Centennial's credit agreement and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum capitalization ratios, minimum interest coverage ratios, minimum consolidated net worth, limitation on priority debt, limitation on sale of assets and limitation on loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2002. In the event Centennial or such subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued as previously described.

The Centennial credit agreement and the Centennial uncommitted long-term master shelf agreement contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the Centennial credit agreement and the Centennial uncommitted long-term master shelf agreement will be in default. The Centennial credit agreement, the Centennial uncommitted long-term master shelf agreement and Centennial's practice limit the amount of subsidiary indebtedness.

International operations A subsidiary of the Company, that has an investment in electric generating facilities in Brazil, has a short-term credit agreement that allows for borrowings of up to $25 million. Under this agreement, $12.0 million was outstanding at December 31, 2002. This subsidiary intends to renew this credit agreement, which expires June 30, 2003. Centennial has guaranteed this short-term credit agreement.

In order to borrow under the credit facility, the subsidiary must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on sale of assets and limitation on loans and investments. This subsidiary was in compliance with these covenants and met the required conditions at December 31, 2002. In the event this subsidiary does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

Williston Basin Interstate Pipeline Company Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the Company, has an uncommitted long-term master shelf agreement that allows for borrowings of up to $100 million. Under the terms of the master shelf agreement, $30.0 million was outstanding at December 31, 2002.

In order to borrow under Williston Basin's uncommitted long-term master shelf agreement, it must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on consolidated indebtedness, limitation on priority debt, limitation on sale of assets and limitation on investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2002. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

Contractual obligations and commercial commitments For more information on the Company's contractual obligations on long-term debt, operating leases and purchase commitments, see Notes 8 and 17 of Notes to Consolidated Financial Statements. At December 31, 2002, the Company's commitments under these obligations were as follows:

	2003	2004	2005	2006	2007	Thereafter	Total
				(In millions)			
Long-term debt	$ 22.1	$173.8	$ 70.3	$100.2	$105.4	$369.8	$ 841.6
Operating leases	19.3	14.3	11.2	7.8	4.3	21.3	78.2
Purchase commitments	171.3	55.4	43.1	37.0	27.6	130.4	464.8
	$212.7	$243.5	$124.6	$145.0	$137.3	$521.5	$1,384.6

Certain subsidiaries of the Company have financial guarantees outstanding at December 31, 2002. These guarantees as of December 31, 2002, are approximately $47.6 million, of which approximately $24.9 million pertain to Centennial's guarantee of certain obligations in connection with the natural gas-fired electric generation station in Brazil. For more information on these guarantees, see Notes 2 and 17 of Notes to Consolidated Financial Statements. As of December 31, 2002, with respect to these guarantees, there was approximately $43.2 million outstanding through 2003, $1.4 million outstanding through 2004 and $3.0 million outstanding thereafter. These guarantees are not reflected in the consolidated financial statements.

As of December 31, 2002, Centennial was contingently liable for performance of certain of its subsidiaries under approximately $200 million of surety bonds. These bonds are principally for construction contracts and reclamation obligations of these subsidiaries, entered into in the normal course of business. Centennial indemnifies the respective surety bond companies against any exposure under the bonds. A large portion of these contingent commitments expire in 2003, however Centennial will likely continue to enter into surety bonds for its subsidiaries in the future.

Approval of audit and nonaudit services

During the fourth quarter of 2002, the Company's Audit Committee pre-approved certain audit services relating to comfort letters and consents in connection with registration statements and other Securities and Exchange Commission (SEC) required filings and audit reviews in connection with such filings, audit reviews in connection with business combinations, and additional audit services required in connection with quarterly reviews and annual audits. The Audit Committee also approved certain nonaudit services, relating to tax services in connection with domestic and international operations, and training on accounting and SEC compliance.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2002, 2001 or 2000.

Quantitative and Qualitative Disclosures about Market Risk

The Company is exposed to the impact of market fluctuations associated with commodity prices, interest rates and foreign currency. The Company has policies and procedures to assist in controlling these market risks and utilizes derivatives to manage a portion of its risk.

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly, and that all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and that any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings and credit exposure limitations. Accordingly, the Company does not anticipate any material effect to its financial position or results of operations as a result of nonperformance by counterparties.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; or if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting will be discontinued, and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in other accumulated comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

Commodity price risk

A subsidiary of the Company utilizes natural gas and oil price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on the subsidiary's forecasted sales of natural gas and oil production. Each of the natural gas and oil price swap and collar agreements were designated as a hedge of the forecasted sale of natural gas and oil production.

On an ongoing basis, the balance sheet is adjusted to reflect the current fair market value of the swap and collar agreements. The related gains or losses on these agreements are recorded in common stockholders' equity as a component of other comprehensive income (loss). At the date the underlying transaction occurs, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

The following table summarizes hedge agreements entered into by a wholly owned subsidiary of the Company, as of December 31, 2002. These agreements call for the subsidiary to receive fixed prices and pay variable prices.

(Notional amount and fair value in thousands)

	Weighted Average Fixed Price (Per MMBtu)	Notional Amount (In MMBtu's)	Fair Value
Natural gas swap agreements maturing in 2003	$3.96	1,186	$ (731)

	Weighted Average Floor/Ceiling Price (Per MMBtu)	Notional Amount (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2003	$3.33/$3.89	22,365	$(6,256)

	Weighted Average Floor/Ceiling Price (Per barrel)	Notional Amount (In barrels)	Fair Value
Oil collar agreements maturing in 2003	$24.50/$27.62	639	$ (457)

The following table summarizes hedge agreements entered into by certain wholly owned subsidiaries of the Company, as of December 31, 2001. These agreements call for the subsidiaries to receive fixed prices and pay variable prices.

(Notional amount and fair value in thousands)

	Weighted Average Fixed Price (Per MMBtu)	Notional Amount (In MMBtu's)	Fair Value
Natural gas swap agreement maturing in 2002	$4.34	1,150	$1,878

	Weighted Average Fixed Price (Per barrel)	Notional Amount (In barrels)	Fair Value
Oil swap agreements maturing in 2002	$24.96	405	$1,789

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by taking advantage of market conditions when timing the placement of long-term or permanent financing. The Company has also historically used interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk. As of December 31, 2002, the Company also has outstanding 13,000 shares of 5.10% Series preferred stock subject to mandatory redemption. The Company is obligated to make annual sinking fund contributions to retire the preferred stock and pay cumulative preferred dividends at a fixed rate of 5.10 percent.

The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates as well as the aggregate annual sinking fund amount applicable to preferred stock subject to mandatory redemption and the related dividend rate, as of December 31, 2002. Weighted average variable rates are based on forward rates as of December 31, 2002.

	2003	2004	2005	2006	2007	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$22.1	$ 21.9	$70.3	$100.2	$105.4	$369.8	$689.7	$742.7
Weighted average interest rate	7.4%	6.6%	8.0%	6.5%	8.2%	6.6%	7.0%	–
Variable rate	–	$151.9	–	–	–	–	$151.9	$145.4
Weighted average interest rate	–	1.5%	–	–	–	–	1.5%	–
Preferred stock subject to mandatory redemption	$ .1	$ .1	$ .1	$ .1	$ .1	$ .8	$ 1.3	$ 1.2
Dividend rate	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	5.1%	–

For further information on derivative instruments and fair value of other financial instruments, see Notes 5 and 6 of Notes to Consolidated Financial Statements.

Foreign currency risk

A subsidiary of the Company has a 49 percent equity investment in a 200-megawatt natural gas-fired electric generation project (Project) in Brazil, which has a portion of its borrowings and payables denominated in U.S. dollars. The subsidiary has exposure to currency exchange risk as a result of fluctuations in currency exchange rates between the U.S. dollar and the Brazilian real. The functional currency for the Project is the Brazilian real. For further information on this investment, see Note 2 of Notes to Consolidated Financial Statements.

The subsidiary's equity income from this Brazilian investment is impacted by fluctuations in currency exchange rates on transactions denominated in a currency other than the Brazilian real, including the effects of changes in currency exchange rates with respect to the Project's U.S. dollar denominated obligations, excluding a U.S. dollar denominated loan from the subsidiary as discussed below. At December 31, 2002, these U.S. dollar denominated obligations approximated $47.5 million. If, for example, the value of the Brazilian real decreased in relation to the U.S. dollar by 10 percent, the subsidiary, with respect to its interest in the Project, would record a foreign currency transaction loss in net income of approximately $2.1 million based on the above U.S. dollar denominated obligations at December 31, 2002. The Project also had US$27.6 million Brazilian real denominated obligations at December 31, 2002.

Adjustments attributable to the translation from the Brazilian real to the U.S. dollar for assets, liabilities, revenues and expenses were recorded in accumulated other comprehensive income at December 31, 2002.

The Project also had U.S. dollar denominated borrowings payable to the subsidiary of $20.0 million at December 31, 2002. Foreign currency translation adjustments on the Project's borrowings payable to the subsidiary are recorded in accumulated other comprehensive income.

The subsidiary's investment in this Project at December 31, 2002, was $27.8 million. Centennial has guaranteed Project obligations and loans of approximately $24.9 million as of December 31, 2002.

The subsidiary is managing a portion of its foreign currency exchange risk through contractual provisions, that are largely indexed to the U.S. dollar, contained in the Project's power purchase agreement with Petrobras. On August 12, 2002, the subsidiary entered into a foreign currency collar agreement for a notional amount of $21.3 million, with a fixed price floor of R$3.10 and a fixed price ceiling of R$3.40, to manage a portion of its foreign currency risk. The collar agreement expired on February 3, 2003. Gains or losses on this derivative instrument are recorded in earnings each period. The fair value of the foreign currency collar agreement at December 31, 2002, was approximately $903,000 ($566,000 after tax). From time to time, derivative instruments may be utilized to manage a portion of the foreign currency risk.

The management of MDU Resources Group, Inc. is responsible for the preparation, integrity and objectivity of the financial information contained in the consolidated financial statements and elsewhere in this Annual Report. The financial statements have been prepared in conformity with accounting principles generally accepted in the United States of America as applied to the company's regulated and nonregulated businesses and necessarily include some amounts that are based on informed judgments and estimates of management.

To meet its responsibilities with respect to financial information, management maintains and enforces a system of internal accounting controls designed to provide assurance, on a cost-effective basis, that transactions are carried out in accordance with management's authorizations and that assets are safeguarded against loss from unauthorized use or disposition. The system includes an organizational structure which provides an appropriate segregation of responsibilities, effective selection and training of personnel, written policies and procedures and periodic reviews by the Internal Auditing Department. In addition, the company has a policy which requires certain employees to acknowledge their responsibility for ethical conduct. Management believes that these measures provide for a system that is effective and reasonably assures that all transactions are properly recorded for the preparation of financial statements. Management modifies and improves its system of internal accounting controls in response to changes in business conditions. The company's Internal Auditing Department is charged with the responsibility for determining compliance with company procedures.

The Board of Directors, through its Audit Committee which is comprised entirely of outside directors, oversees management's responsibilities for financial reporting. The Audit Committee meets regularly with management, the internal auditors and Deloitte & Touche LLP, independent auditors, to discuss auditing and financial matters and to assure that each is carrying out its responsibilities. The internal auditors and Deloitte & Touche LLP have full and free access to the Audit Committee, without management present, to discuss auditing, internal accounting control and financial reporting matters.

Deloitte & Touche LLP is engaged to express an opinion on the financial statements. Their audit is conducted in accordance with auditing standards generally accepted in the United States of America and includes examining, on a test basis, supporting evidence, assessing the company's accounting principles used and significant estimates made by management and evaluating the overall financial statement presentation to the extent necessary to allow them to report on the fairness, in all material respects, of the financial condition and operating results of the company.

Martin A. White	Warren L. Robinson
Chairman of the Board	Executive Vice President
President and	Treasurer and
Chief Executive Officer	Chief Financial Officer

Years ended December 31,	2002	2001	2000
	(In thousands, except per share amounts)		
Operating revenues	$2,031,537	$2,223,632	$1,873,671
Operating expenses:			
Fuel and purchased power	56,010	57,393	54,114
Purchased natural gas sold	92,528	529,356	634,277
Operation and maintenance	1,393,028	1,168,271	812,600
Depreciation, depletion and amortization	157,961	139,917	110,888
Taxes, other than income	65,893	55,427	44,805
	1,765,420	1,950,364	1,656,684
Operating income	266,117	273,268	216,987
Other income – net	13,572	26,821	11,724
Interest expense	45,015	45,899	48,033
Income before income taxes	234,674	254,190	180,678
Income taxes	86,230	98,341	69,650
Net income	148,444	155,849	111,028
Dividends on preferred stocks	756	762	766
Earnings on common stock	$ 147,688	$ 155,087	$ 110,262
Earnings per common share – basic	$ 2.09	$ 2.31	$ 1.80
Earnings per common share – diluted	$ 2.07	$ 2.29	$ 1.80
Dividends per common share	$ .94	$ .90	$ .86
Weighted average common shares outstanding – basic	70,743	67,272	61,090
Weighted average common shares outstanding – diluted	71,242	67,869	61,390

The accompanying notes are an integral part of these consolidated statements.

December 31,	2002	2001
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 67,556	$ 41,811
Receivables, net	325,395	285,081
Inventories	93,123	95,341
Deferred income taxes	8,877	18,973
Prepayments and other current assets	42,597	40,286
	537,548	481,492
Investments	42,864	38,198
Property, plant and equipment	3,003,996	2,647,121
Less accumulated depreciation, depletion and amortization	1,079,110	942,723
	1,924,886	1,704,398
Deferred charges and other assets:		
Goodwill (Note 3)	190,999	173,997
Other intangible assets, net (Note 3)	176,164	163,978
Other	64,788	61,008
	431,951	398,983
	$2,937,249	$2,623,071
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings (Note 7)	$ 20,000	$ –
Long-term debt and preferred stock due within one year	22,183	11,185
Accounts payable	132,120	110,649
Taxes payable	13,108	11,826
Dividends payable	17,959	16,108
Other accrued liabilities	94,275	95,559
	299,645	245,327
Long-term debt (Note 8)	819,558	783,709
Deferred credits and other liabilities:		
Deferred income taxes	374,097	342,412
Other liabilities	144,004	125,552
	518,101	467,964
Preferred stock subject to mandatory redemption (Note 9)	1,200	1,300
Commitments and contingencies (Notes 14, 16 and 17)		
Stockholders' equity:		
Preferred stocks (Note 9)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 10)		
Authorized – 250,000,000 shares, $1.00 par value in 2002, 150,000,000 shares, $1.00 par value in 2001		
Issued – 74,282,038 shares in 2002 and 70,016,851 shares in 2001	74,282	70,017
Other paid-in capital	748,095	646,521
Retained earnings	474,798	394,641
Accumulated other comprehensive income (loss)	(9,804)	2,218
Treasury stock at cost – 239,521 shares	(3,626)	(3,626)
Total common stockholders' equity	1,283,745	1,109,771
Total stockholders' equity	1,298,745	1,124,771
	$2,937,249	$2,623,071

The accompanying notes are an integral part of these consolidated statements.

Years ended December 31, 2002, 2001 and 2000

	Common Stock		Other	Retained	Accumulated Other Comprehensive Income	Treasury Stock		
	Shares	Amount	Paid-in Capital	Earnings	(Loss)	Shares	Amount	Total
				(In thousands, except shares)				
Balance at December 31, 1999	57,277,915	$57,278	$372,312	$243,569	$ –	(239,521)	$(3,626)	$ 669,533
Net income	–	–	–	111,028	–	–	–	111,028
Dividends on preferred stocks	–	–	–	(766)	–	–	–	(766)
Dividends on common stock	–	–	–	(53,184)	–	–	–	(53,184)
Issuance of common stock, net	7,989,652	7,990	146,459	–	–	–	–	154,449
Balance at December 31, 2000	65,267,567	65,268	518,771	300,647	–	(239,521)	(3,626)	881,060
Comprehensive income:								
Net income	–	–	–	155,849	–	–	–	155,849
Other comprehensive income, net of tax –								
Net unrealized gain on derivative instruments qualifying as hedges	–	–	–	–	2,218	–	–	2,218
Total comprehensive income	–	–	–	–	–	–	–	158,067
Dividends on preferred stocks	–	–	–	(762)	–	–	–	(762)
Dividends on common stock	–	–	–	(61,093)	–	–	–	(61,093)
Issuance of common stock, net	4,749,284	4,749	127,750	–	–	–	–	132,499
Balance at December 31, 2001	70,016,851	70,017	646,521	394,641	2,218	(239,521)	(3,626)	1,109,771
Comprehensive income:								
Net income	–	–	–	148,444	–	–	–	148,444
Other comprehensive loss, net of tax –								
Net unrealized loss on derivative instruments qualifying as hedges	–	–	–	–	(6,759)	–	–	(6,759)
Minimum pension liability adjustment	–	–	–	–	(4,464)	–	–	(4,464)
Foreign currency translation adjustment	–	–	–	–	(799)	–	–	(799)
Total comprehensive income	–	–	–	–	–	–	–	136,422
Dividends on preferred stocks	–	–	–	(756)	–	–	–	(756)
Dividends on common stock	–	–	–	(67,531)	–	–	–	(67,531)
Issuance of common stock, net	4,265,187	4,265	101,574	–	–	–	–	105,839
Balance at December 31, 2002	74,282,038	$74,282	$748,095	$474,798	$(9,804)	(239,521)	$(3,626)	$1,283,745

The accompanying notes are an integral part of these consolidated statements.

Years ended December 31,	2002	2001	2000
		(In thousands)	
Operating activities:			
Net income	$ 148,444	$ 155,849	$ 111,028
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	157,961	139,917	110,888
Deferred income taxes and investment tax credit	30,759	21,014	36,530
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(19,739)	127,267	(117,449)
Inventories	6,537	(26,540)	9,578
Other current assets	(5,562)	(2,792)	(3,514)
Accounts payable	11,600	(90,576)	61,021
Other current liabilities	(9,499)	34,331	(3,821)
Other noncurrent changes	5,830	(9,916)	2,701
Net cash provided by operating activities	326,331	348,554	206,962
Investing activities:			
Capital expenditures	(276,776)	(269,542)	(254,940)
Acquisitions, net of cash acquired	(92,657)	(112,743)	(153,886)
Net proceeds from sale or disposition of property	16,217	51,641	11,000
Investments	(4,666)	2,760	2,102
Additions to notes receivable	–	(23,813)	(5,000)
Proceeds from notes receivable	4,000	4,000	4,000
Net cash used in investing activities	(353,882)	(347,697)	(396,724)
Financing activities:			
Net change in short-term borrowings	20,000	(8,000)	(7,242)
Issuance of long-term debt	129,072	122,283	192,162
Repayment of long-term debt	(82,523)	(115,062)	(29,349)
Retirement of preferred stock	(100)	(100)	(100)
Proceeds from issuance of common stock, net	55,134	67,176	47,249
Dividends paid	(68,287)	(61,855)	(53,950)
Net cash provided by financing activities	53,296	4,442	148,770
Increase (decrease) in cash and cash equivalents	25,745	5,299	(40,992)
Cash and cash equivalents – beginning of year	41,811	36,512	77,504
Cash and cash equivalents – end of year	$ 67,556	$ 41,811	$ 36,512

The accompanying notes are an integral part of these consolidated statements.

NOTE 1
Summary of Significant Accounting Policies

Basis of presentation

The consolidated financial statements of MDU Resources Group, Inc. and its subsidiaries (Company) include the accounts of the following segments: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, construction materials and mining and independent power production. The electric and natural gas distribution segments and a portion of the pipeline and energy services segment are regulated. The Company's nonregulated operations include the utility services, natural gas and oil production, construction materials and mining, and independent power production segments, and a portion of the pipeline and energy services segment. For further descriptions of the Company's business segments, see Note 12. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generation stations.

The Company uses the equity method of accounting for its 49 percent interest in MPX Holdings, Ltda. (MPX), which was formed to develop electric generation and transmission, steam generation, power equipment and coal mining projects in Brazil. For more information on the Company's equity investment, see Note 2.

The Company's regulated businesses are subject to various state and federal agency regulation. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the Federal Energy Regulatory Commission (FERC). These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Regulation" (SFAS No. 71). SFAS No. 71 requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 4 for more information regarding the nature and amounts of these regulatory deferrals.

Prior to the sale of the Company's coal operations as discussed in Note 12, intercompany coal sales, which were made at prices approximately the same as those charged to others, and the related utility fuel purchases were not eliminated in accordance with the provisions of SFAS No. 71. All other significant intercompany balances and transactions have been eliminated in consolidation.

Cash and cash equivalents

The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Allowance for doubtful accounts

The Company's allowance for doubtful accounts as of December 31, 2002 and 2001, was $8.2 million and $5.8 million, respectively.

Natural gas in underground storage

Natural gas in underground storage for the Company's regulated operations is carried at cost using the last-in, first-out method. The portion of the cost of natural gas in underground storage expected to be used within one year was included in inventories and amounted to $18.2 million and $28.6 million at December 31, 2002 and 2001, respectively. The remainder of natural gas in underground storage was included in property, plant and equipment and was $42.2 million and $43.1 million at December 31, 2002 and 2001, respectively.

Inventories

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of materials and supplies of $23.0 million and $22.5 million, aggregates held for resale of $39.6 million and $31.1 million and other inventories of $12.3 million and $13.1 million as of December 31, 2002 and 2001, respectively. These inventories were stated at the lower of average cost or market.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost when first placed in service. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost and cost of removal, less salvage, is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for natural gas and oil production properties as described below, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize an allowance for funds used during construction (AFUDC) on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $7.6 million, $6.6 million and $5.2 million in 2002, 2001 and 2000, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable reserves, which are depleted based on the units of production method based on recoverable deposits, and natural gas and oil production properties as described below.

Property, plant and equipment at December 31, 2002 and 2001, was as follows:

	2002	2001	Estimated Depreciable Life in Years
	(Dollars in thousands)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	$ 619,230	$ 597,080	4–50
Natural gas distribution:			
Natural gas distribution plant *(a)*	246,844	238,566	4–40
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities *(b)*	303,245	294,237	3–70
Nonregulated:			
Utility services:			
Land	2,601	2,330	–
Buildings and improvements	8,768	4,586	10–40
Machinery, vehicles and equipment	54,833	46,090	2–10
Other	4,458	6,184	3–10
Pipeline and energy services:			
Natural gas gathering and other facilities	108,179	108,482	3–30
Energy services	1,270	7,330	3–15
Natural gas and oil production:			
Natural gas and oil properties	748,844	628,509	*(c)*
Other	6,944	2,317	5–7
Construction materials and mining:			
Land	85,376	80,526	–
Buildings and improvements	43,144	43,069	3–39
Machinery, vehicles and equipment	493,349	412,856	3–20
Construction in progress	10,151	10,631	–
Depletable reserves	172,235	164,328	*(d)*
Independent power production:			
Electric generation	58,000	–	20–30
Other	36,525	–	3–20
Less accumulated depreciation, depletion and amortization	1,079,110	942,723	
Net property, plant and equipment	$1,924,886	$1,704,398	

(a) Includes natural gas in underground storage of $1.9 million and $2.8 million at December 31, 2002 and 2001, respectively, which is not subject to depreciation.

(b) Includes natural gas in underground storage of $40.3 million at December 31, 2002 and 2001, which is not subject to depreciation.

(c) Amortized on the units of production method based on total proved reserves.

(d) Depleted based on the units of production method based on recoverable deposits.

NOTE 1
(Continued)

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In 2000, the Company experienced significant changes in market conditions at one of its energy marketing operations, which negatively affected the fair value of the assets at that operation. Due to the significance of the decline, the Company recorded an impairment charge of $3.9 million after tax in 2000. The amount related to this impairment is included in depreciation, depletion and amortization. Excluding this impairment, no other long-lived assets have been impaired and, accordingly, no other impairment losses have been recorded in 2002, 2001 and 2000. Unforeseen events and changes in circumstances could require the recognition of other impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. On January 1, 2002, the Company adopted Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangibles" (SFAS No. 142) and ceased amortization of its goodwill. Goodwill is required to be tested for impairment annually, or more frequently if events or changes in circumstances indicate that goodwill may be impaired. In accordance with SFAS No. 142, the Company performed its transitional goodwill impairment testing as of January 1, 2002, and performed its annual goodwill impairment testing as of October 31, 2002, and determined that no impairments existed at those dates. For more information on goodwill and the adoption of SFAS No. 142, see Note 3 and new accounting standards in Note 1 as discussed below.

Impairment testing of natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units of production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are treated as adjustments to the cost of the properties with no gain or loss recognized. Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net revenues of proved reserves based on single point in time spot market prices, as mandated under the rules of the Securities and Exchange Commission, and the lower of cost or fair value of unproved properties. Future net revenue is estimated based on end-of-quarter spot market prices adjusted for contracted price changes. If capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter unless subsequent price changes eliminate or reduce an indicated write-down.

At December 31, 2002 and 2001, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2002, could result in a future write-down of the Company's natural gas and oil properties.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is probable. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed below. The Company recognizes revenue from natural gas and oil production activities only on that portion of production sold and allocable to the Company's ownership interest in the related well. The Company recognizes all other revenues when services are rendered or goods are delivered.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed price and modified fixed price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. Costs in excess of billings on uncompleted contracts of $19.4 million and $29.7 million for the years ended December 31, 2002 and 2001, respectively, represents revenues recognized in excess of amounts billed and was included in receivables, net. Billings in excess of costs on uncompleted contracts of $24.5 million and $17.3 million for the years ended December 31, 2002 and 2001, respectively, represents billings in excess of revenues recognized and was included in accounts payable. Also included in receivables, net were amounts representing balances billed but not paid by customers under retainage provisions in contracts that amounted to $25.6 million and $20.5 million as of December 31, 2002 and 2001, respectively.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties. The Company's policy requires settlement of natural gas and oil price derivative instruments monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. These policies and procedures include an evaluation of potential counterparties' credit ratings and credit exposure limitations. Accordingly, the Company does not anticipate any material effect to its financial position or results of operations as a result of nonperformance by counterparties.

Advertising

The Company expenses advertising costs as incurred, and the amount of advertising expense for the years 2002, 2001 and 2000, was $3.4 million, $2.9 million and $2.0 million, respectively.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 24 months to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments amounted to $2.4 million and $27.7 million at December 31, 2002 and 2001, respectively, and are included in other accrued liabilities.

Insurance

Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $500,000 per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $500,000 per accident or occurrence. These subsidiaries have excess coverage on a per occurrence basis beyond the deductible levels. The subsidiaries of the Company are insuring for losses up to the deductible amounts, which are accrued based on estimates of the liability for claims incurred and an estimate of claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting from the Company's adoption of Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in other accrued liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

NOTE 1 (Continued)

Foreign currency translation adjustment

The functional currency of the Company's investment in a 200-megawatt natural gas-fired power plant in Brazil, as further discussed in Note 2, is the Brazilian real. Translation from the Brazilian real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses have been translated using the weighted average exchange rate for each month prevailing during the period reported. Adjustments resulting from such translations are reported as a separate component of other comprehensive income in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity are recorded in income.

Earnings per common share

Basic earnings per common share were computed by dividing earnings on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options and restricted stock grants. For the years ended December 31, 2002 and 2001, 2,449,950 shares and 150,630 shares, respectively, with an average exercise price of $30.13 and $36.86, respectively, attributable to the exercise of outstanding options, were excluded from the calculation of diluted earnings per share because their effect was antidilutive. For the year ended December 31, 2000, there were no shares excluded from the calculation of diluted earnings per share. For the years ended December 31, 2002, 2001 and 2000, no adjustments were made to reported earnings in the computation of earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation

The Company has stock option plans for directors, key employees and employees and accounts for these option plans in accordance with Accounting Principles Board (APB) Opinion No. 25 under which no compensation cost has been recognized. For more information on the Company's stock-based compensation, see Note 10.

The following table illustrates the effect on earnings and earnings per common share for the years ended December 31, 2002, 2001 and 2000, as if the Company had applied Statement of Financial Accounting Standards No. 123, "Accounting for Stock-Based Compensation" (SFAS No. 123) to its stock-based compensation:

	2002	2001	2000
	(In thousands, except per share amounts)		
Earnings on common stock, as reported	$147,688	$155,087	$110,262
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	(2,862)	(3,799)	(529)
Pro forma earnings on common stock	$144,826	$151,288	$109,733
Earnings per common share:			
Basic – as reported	$ 2.09	$ 2.31	$ 1.80
Basic – pro forma	$ 2.05	$ 2.25	$ 1.80
Diluted – as reported	$ 2.07	$ 2.29	$ 1.80
Diluted – pro forma	$ 2.03	$ 2.23	$ 1.79

Use of estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires the Company 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. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the purchase method of accounting; natural gas and oil reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; the valuation of stock-based compensation; and the fair value of an embedded derivative in a power purchase agreement related to an equity method investment in Brazil, as discussed in Note 2. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information

Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2002	2001	2000
		(In thousands)	
Interest, net of amount capitalized	$37,788	$42,267	$41,912
Income taxes	$60,988	$75,284	$30,930

Reclassifications

Certain reclassifications have been made in the financial statements for prior years to conform to the current presentation. Such reclassifications had no effect on net income or stockholders' equity as previously reported.

New accounting standards

In June 2001, the Financial Accounting Standards Board (FASB) approved SFAS No. 142. SFAS No. 142 changes the accounting for goodwill and intangible assets and requires that goodwill no longer be amortized but be tested for impairment at least annually at the reporting unit level in accordance with SFAS No. 142. Recognized intangible assets with determinable useful lives should be amortized over their useful lives and reviewed for impairment in accordance with Statement of Financial Accounting Standards No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." For more information on the adoption of SFAS No. 142, see Note 3.

In June 2001, the FASB approved Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations" (SFAS No. 143). SFAS No. 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 a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, an entity either settles the obligation for the recorded amount or incurs a gain or loss upon settlement. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002.

The Company has identified certain asset retirement obligations that will be subject to the standard and adopted SFAS No. 143 on January 1, 2003. These obligations include the plugging and abandonment of natural gas and oil wells; decommissioning of certain electric generating facilities; reclamation of certain aggregate properties; removal of certain natural gas distribution, transmission, storage and gathering facilities, and certain other obligations associated with leased properties. Certain natural gas distribution, transmission, storage and gathering facilities have been determined to have indeterminate useful lives. The adoption of SFAS No. 143 is expected to result in a one-time cumulative effect after-tax charge to earnings in the range of $7.0 million to $10.0 million and also is estimated to reduce 2003 earnings before the cumulative effect charge by approximately $1.6 million to $2.1 million. In addition, a regulatory asset that is approximated to be less than $1.0 million will be recognized for the transition amount that is expected to be recovered in rates over time. The Company intends to record the cumulative charge and regulatory asset in the first quarter of 2003.

NOTE 1 (Continued)

In April 2002, the FASB approved Statement of Financial Accounting Standards No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections" (SFAS No. 145). FASB No. 4 required all gains or losses from extinguishment of debt to be classified as extraordinary items net of income taxes. SFAS No. 145 requires that gains and losses from extinguishment of debt be evaluated under the provisions of APB Opinion No. 30, and be classified as ordinary items unless they are unusual or infrequent or meet the specific criteria for treatment as an extraordinary item. SFAS No. 145 is effective for fiscal years beginning after May 15, 2002. The Company believes the adoption of SFAS No. 145 will not have a material effect on its financial position or results of operations.

In June 2002, the FASB approved Statement of Financial Accounting Standards No. 146, "Accounting for Costs Associated with Exit or Disposal Activities" (SFAS No. 146). SFAS No. 146 addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)" (EITF No. 94-3). SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF No. 94-3. SFAS No. 146 is to be applied prospectively to exit or disposal activities initiated after December 31, 2002, and is not expected to have a material effect on the Company's financial position or results of operations.

In September 2002, the Emerging Issues Task Force (EITF) reached a consensus in EITF Issue No. 02-13, "Deferred Income Tax Considerations in Applying the Goodwill Impairment Test in FASB Statement No. 142, Goodwill and Other Intangible Assets" (EITF No. 02-13) that the determination of whether to estimate the fair value of a reporting unit by assuming that the unit could be bought or sold in a nontaxable transaction versus a taxable transaction is a matter of judgment that depends on the relevant facts and circumstances. The EITF also reached the consensus that deferred income taxes should be included in the carrying value of the reporting unit, regardless of whether the fair value of the reporting unit will be determined assuming it would be bought or sold in a taxable or nontaxable transaction. In addition, EITF No. 02-13 states that for purposes of determining the implied fair value of a reporting unit's goodwill, an entity should use the income tax bases of a reporting unit's assets and liabilities implicit in the tax structure assumed in its estimation of fair value of the reporting unit. EITF No. 02-13 did not have a material effect on the Company's goodwill impairment testing.

In October 2002, the EITF reached a consensus in EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 02-3) to rescind EITF Issue No. 98-10 "Accounting for Contracts Involved in Energy Trading and Risk Management Activities" (EITF No. 98-10). The impact of the rescission of EITF No. 98-10 is to preclude mark-to-market accounting for all energy trading contracts not within the scope of Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities", as amended, (SFAS No. 133). In addition, the EITF reached a consensus that gains and losses on derivative instruments within the scope of SFAS No. 133 should be shown net in the income statement if the derivative instruments are held for trading purposes. The adoption of EITF No. 02-3 and rescission of EITF No. 98-10 did not have a material effect on the Company's financial position or results of operations.

In November 2002, the FASB issued FASB Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (Interpretation No. 45). Interpretation No. 45 clarifies the disclosures to be made by a guarantor in its interim and annual financial statements about its obligations under certain guarantees that it has issued. Interpretation No. 45 also requires a guarantor to recognize, at the inception of a guarantee, a liability for the fair value of the obligation undertaken in issuing certain types of guarantees. Certain types of guarantees are not subject to the initial recognition and measurement provisions of Interpretation No. 45 but are subject to its disclosure requirements. The initial recognition and initial measurement provisions of Interpretation No. 45 are applicable on a prospective basis to guarantees issued or modified after December 31, 2002, regardless of the guarantor's fiscal year-end. The guarantor's previous accounting for guarantees issued prior to the date of the initial application of Interpretation No. 45 shall not be revised or restated. The disclosure requirements in Interpretation No. 45 are effective for financial statements of interim or annual periods ended after December 15, 2002. The Company will apply the initial recognition and initial measurement provisions of Interpretation No. 45 to guarantees issued or modified after December 31, 2002. For more information on the Company's guarantees and the disclosure requirements of Interpretation No. 45, as applicable to the Company, see Note 17.

In December 2002, the FASB approved Statement of Financial Accounting Standards No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123" (SFAS No. 148). SFAS No. 148 amends SFAS No. 123 to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. SFAS No. 148 is effective for financial statements for fiscal years ending after December 15, 2002. The Company had adopted the disclosure provisions of SFAS No. 148 at December 31, 2002.

Comprehensive income

Comprehensive income is the sum of net income as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains and losses on derivative instruments qualifying as hedges, a minimum pension liability adjustment and a foreign currency translation adjustment.

The components of other comprehensive income (loss) and their related tax effects for the years ended December 31, 2002, 2001 and 2000, were as follows:

	2002	2001	2000
		(In thousands)	
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Unrealized loss on derivative instruments at January 1, 2001, due to cumulative effect of a change in accounting principle, net of tax of $3,970 in 2001	$ –	$(6,080)	$ –
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $2,903 and $1,448 in 2002 and 2001, respectively	(4,541)	2,218	–
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $1,448 and $3,970 in 2002 and 2001, respectively	2,218	(6,080)	–
Net unrealized gain (loss) on derivative instruments qualifying as hedges	(6,759)	2,218	–
Minimum pension liability adjustment, net of tax of $2,876 in 2002	(4,464)	–	–
Foreign currency translation adjustment	(799)	–	–
Total other comprehensive income (loss)	$(12,022)	$ 2,218	$ –

The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2002, 2001 and 2000, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Minimum Pension Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Income (Loss)
		(In thousands)		
Balance at December 31, 2000	$ –	$ –	$ –	$ –
Balance at December 31, 2001	$ 2,218	$ –	$ –	$ 2,218
Balance at December 31, 2002	$(4,541)	$(4,464)	$(799)	$(9,804)

NOTE 2 Equity Method Investment

In August 2001, a Brazilian subsidiary of the Company entered into a joint venture agreement with a Brazilian firm under which the parties have formed MPX. This subsidiary has a 49 percent interest in MPX. MPX, through a wholly owned subsidiary, has constructed a 200-megawatt natural gas-fired power plant (Project) in the Brazilian state of Ceara. The first 100 megawatts entered commercial service in July 2002, and the second 100 megawatts entered commercial service in January 2003. Petrobras, the partially Brazilian state-owned energy company, has agreed to purchase all of the capacity and market all of the Project's energy. Petrobras commenced making capacity payments in the third quarter of 2002. The power purchase agreement with Petrobras expires in May 2008. Petrobras also is under contract for five years to supply natural gas to the Project. This contract is renewable for an additional 13 years. The functional currency for the Project is the Brazilian real. The power purchase agreement with Petrobras contains an embedded derivative, which derives its value from an annual adjustment factor, which largely indexes the contract capacity payments to the U.S. dollar. At December 31, 2002, the Company's 49 percent share of the gain from the embedded derivative in the power purchase agreement was $13.6 million (after tax). In addition, the Company's 49 percent share of the foreign currency losses resulting from devaluation of the Brazilian real totaled $9.4 million (after tax) for the year ended December 31, 2002.

The Company's investment in the Project has been accounted for under the equity method of accounting, and the Company's share of net income for the year ended December 31, 2002, was included in other income – net. At December 31, 2002 and 2001, the Company's investment in the Project was approximately $27.8 million and $23.8 million, respectively.

NOTE 3 Goodwill and Other Intangible Assets

The Company adopted SFAS No. 142, as discussed in Note 1, on January 1, 2002. The Company completed its transitional goodwill impairment testing as of January 1, 2002, and performed its annual goodwill impairment testing as of October 31, 2002, and determined that no impairments existed at those dates. Therefore, no impairment loss has been recorded for the year ended December 31, 2002.

On January 1, 2002, in accordance with SFAS No. 142, the Company ceased amortization of its goodwill recorded in business combinations that occurred on or before June 30, 2001. The following information is presented as if SFAS No. 142 was adopted as of January 1, 2000. The reconciliation of previously reported earnings and earnings per common share to the amounts adjusted for the exclusion of goodwill amortization, net of the related income tax effects, for the years ended December 31, 2002, 2001 and 2000, were as follows:

	2002	2001	2000
	(In thousands, except per share amounts)		
Reported earnings on common stock	$147,688	$155,087	$110,262
Add: Goodwill amortization, net of tax	–	3,649	2,741
Adjusted earnings on common stock	$147,688	$158,736	$113,003
Reported earnings per common share – basic	$ 2.09	$ 2.31	$ 1.80
Add: Goodwill amortization, net of tax	–	.05	.05
Adjusted earnings per common share – basic	$ 2.09	$ 2.36	$ 1.85
Reported earnings per common share – diluted	$ 2.07	$ 2.29	$ 1.80
Add: Goodwill amortization, net of tax	–	.05	.04
Adjusted earnings per common share – diluted	$ 2.07	$ 2.34	$ 1.84

The changes in the carrying amount of goodwill for the year ended December 31, 2002, by business segment were as follows:

	Balance as of January 1, 2002	Goodwill Acquired During the Year	Balance as of December 31, 2002
		(In thousands)	
Electric	$ –	$ –	$ –
Natural gas distribution	–	–	–
Utility services	61,909	578	62,487
Pipeline and energy services	9,336	158	9,494
Natural gas and oil production	–	–	–
Construction materials and mining	102,752	9,135	111,887
Independent power production	–	7,131	7,131
Total	$173,997	$17,002	$190,999

Other intangible assets at December 31, 2002 and 2001, were as follows:

	2002	2001
	(In thousands)	
Amortizable intangible assets:		
Leasehold rights	$172,496	$164,446
Accumulated amortization	(7,494)	(4,896)
	165,002	159,550
Noncompete agreements	12,075	12,034
Accumulated amortization	(9,366)	(8,811)
	2,709	3,223
Other	7,224	1,377
Accumulated amortization	(374)	(172)
	6,850	1,205
Unamortizable intangible assets	1,603	–
Total	$176,164	$163,978

Amortization expense for amortizable intangible assets for the year ended December 31, 2002, was $3.4 million. Estimated amortization expense for amortizable intangible assets is $4.4 million in 2003, $4.3 million in 2004, $4.4 million in 2005, $3.1 million in 2006, $3.1 million in 2007 and $155.3 million thereafter.

NOTE 4 Regulatory Assets and Liabilities

The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	2002	2001
	(In thousands)	
Regulatory assets:		
Long-term debt refinancing costs	$ 5,627	$ 6,829
Deferred income taxes	4,230	13,417
Plant costs	2,330	2,499
Postretirement benefit costs	616	722
Other	4,788	5,929
Total regulatory assets	17,591	29,396
Regulatory liabilities:		
Taxes refundable to customers	11,699	12,318
Reserves for regulatory matters	9,856	7,132
Plant decommissioning costs	8,879	8,243
Deferred income taxes	5,491	5,661
Natural gas costs refundable through rate adjustments	2,396	27,706
Other	2,779	5,053
Total regulatory liabilities	41,100	66,113
Net regulatory position	$(23,509)	$(36,717)

NOTE 4
(Continued)

As of December 31, 2002, substantially all of the Company's regulatory assets, other than certain deferred income taxes, were being reflected in rates charged to customers and are being recovered over the next one to 20 years.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of SFAS No. 71 for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of SFAS No. 71 occurs.

NOTE 5
Derivative Instruments

The Company adopted SFAS No. 133 on January 1, 2001. SFAS No. 133 establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its fair value. SFAS No. 133 requires that changes in the derivative instrument's fair value be recognized currently in earnings unless specific hedge accounting criteria are met. Special accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement, and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

SFAS No. 133 requires that as of the date of initial adoption, the difference between the fair market value of derivative instruments recorded on the balance sheet and the previous carrying amount of those derivative instruments be reported in net income or other comprehensive income (loss), as appropriate, as the cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes." On January 1, 2001, the Company reported a net-of-tax cumulative-effect adjustment of $6.1 million in accumulated other comprehensive loss to recognize at fair value all derivative instruments that are designated as cash flow hedging instruments, which the Company reclassified into earnings during the year ended December 31, 2001. The transition to SFAS No. 133 did not have an effect on the Company's net income at adoption.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; or if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting will be discontinued, and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity.

As of December 31, 2002, certain subsidiaries of the Company held derivative instruments designated as cash flow hedging instruments, and a foreign currency derivative that was not designated as a hedge.

Hedging activities

A subsidiary of the Company utilizes natural gas and oil price swap and collar agreements to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil on the subsidiary's forecasted sales of natural gas and oil production. Centennial Energy Holdings, Inc. (Centennial), a wholly owned subsidiary of the Company, entered into an interest rate swap agreement that expired in the fourth quarter of 2001. The objective for holding the interest rate swap agreement was to manage a portion of Centennial's interest rate risk on the forecasted issuance of fixed-rate debt under Centennial's commercial paper program. Each of the natural gas and oil price swap and collar agreements were designated as a hedge of the forecasted sale of natural gas and oil production and Centennial designated the interest rate swap agreement as a hedge of the risk of changes in interest rates on Centennial's forecasted issuances of fixed-rate debt under Centennial's commercial paper program.

On an ongoing basis, the balance sheet is adjusted to reflect the current fair market value of the swap and collar agreements. The related gains or losses on these agreements are recorded in common stockholders' equity as a component of other comprehensive income (loss). At the date the underlying transaction occurs, the amounts accumulated in other comprehensive income (loss) are reported in the Consolidated Statements of Income. To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the years ended December 31, 2002 and 2001, these subsidiaries of the Company recognized the ineffectiveness of cash flow hedges, which is included in operating revenues and interest expense for the natural gas and oil price swap and collar agreements and the interest rate swap agreement, respectively. For the years ended December 31, 2002 and 2001, the amount of hedge ineffectiveness recognized was immaterial. For the years ended December 31, 2002 and 2001, these subsidiaries did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness and there were no reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on derivative instruments that are reclassified from accumulated other comprehensive income (loss) to current-period earnings are included in the line item in which the hedged item is recorded. As of December 31, 2002, the maximum term of the subsidiary's swap and collar agreements, in which the subsidiary of the Company is hedging its exposure to the variability in future cash flows for forecasted transactions, is 12 months. The subsidiary of the Company estimates that over the next 12 months net losses of approximately $4.5 million will be reclassified from accumulated other comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

Foreign currency derivative

On August 12, 2002, an indirect wholly owned Brazilian subsidiary of the Company entered into a foreign currency collar agreement for a notional amount of $21.3 million with a fixed price floor of R$3.10 and a fixed price ceiling of R$3.40 to manage a portion of its foreign currency risk. A subsidiary of the Company has a 49 percent equity investment in a 200-megawatt natural gas-fired electric generation project in Brazil, which has a portion of its borrowings and payables denominated in U.S. dollars. The Company's Brazilian subsidiary has exposure to currency exchange risk as a result of fluctuations in currency exchange rates between the U.S. dollar and the Brazilian real. The term of the collar agreement is from August 12, 2002, through February 3, 2003, and the collar agreement settles on February 3, 2003.

The foreign currency collar agreement has not been designated as a hedge and is recorded at fair value on the Consolidated Balance Sheets. Gains or losses on this derivative instrument are recorded in other income – net. The Company recorded a gain of $566,000 (after tax) on the foreign currency collar agreement for the year ended December 31, 2002.

Energy marketing

The Company had entered into other derivative instruments that were not designated as hedges in its energy marketing operations. In the third quarter of 2001, the Company sold the vast majority of its energy marketing operations. Net unrealized gains and losses on these derivative instruments were not material for the years ended December 31, 2001 and 2000.

NOTE 6
Fair Value of Other Financial Instruments

The estimated fair value of the Company's long-term debt and preferred stock subject to mandatory redemption is based on quoted market prices of the same or similar issues. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included in current liabilities and current assets at December 31, 2002 and 2001, respectively. The estimated fair value of the Company's foreign currency collar agreement was included in current assets at December 31, 2002. The estimated fair values of the Company's natural gas and oil price swap and collar agreements and foreign currency collar agreement reflect the estimated amounts the Company would receive or pay to terminate the

NOTE 6 (Continued)

contracts at the reporting date based upon quoted market prices of comparable contracts. The estimated fair value of the Company's long-term debt, preferred stock subject to mandatory redemption, natural gas and oil price swap and collar agreements and foreign currency collar agreement at December 31 was as follows:

	2002		2001	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$841,641	$888,066	$794,794	$816,988
Preferred stock subject to mandatory redemption	$ 1,300	$ 1,168	$ 1,400	$ 1,217
Natural gas and oil price swap and collar agreements	$ (7,444)	$ (7,444)	$ 3,667	$ 3,667
Foreign currency collar agreement	$ 903	$ 903	$ –	$ –

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities (excluding unsettled derivative instruments) approximate their fair values because of their short-term nature.

NOTE 7 Short-term Borrowings

MDU Resources Group, Inc.

MDU Resources Group, Inc. (MDU Resources) has unsecured short-term bank lines of credit from several banks totaling $46 million and a revolving credit agreement with various banks totaling $50 million at December 31, 2002. The bank lines of credit provide for commitment fees at varying rates and there were no amounts outstanding under the bank lines of credit or the credit agreement at December 31, 2002 or 2001. The bank lines of credit and the credit agreement support MDU Resources' $75 million commercial paper program. Under the MDU Resources commercial paper program, $58.0 million was outstanding at December 31, 2002, of which $8.0 million was classified as short-term borrowings and $50.0 million was classified as long-term debt. There were no amounts outstanding under MDU Resources' commercial paper program at December 31, 2001. The commercial paper borrowings classified as short term are supported by the short-term bank lines of credit. The commercial paper borrowings classified as long-term debt (see Note 8) are intended to be refinanced on a long-term basis through continued MDU Resources commercial paper borrowings supported by the credit agreement, which allows for subsequent borrowings up to a term of one year. MDU Resources intends to renew or replace the existing credit agreement, which expires December 30, 2003.

In order to borrow under MDU Resources' credit agreement, MDU Resources must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum leverage ratios, minimum interest coverage ratio, limitation on sale of assets and limitation on investments. MDU Resources was in compliance with these covenants and met the required conditions at December 31, 2002.

Currently, there are no credit facilities that contain cross-default provisions between MDU Resources and any of its subsidiaries.

International operations

A subsidiary of the Company, which has an investment in electric generating facilities in Brazil, has a short-term credit agreement that allows for borrowings of up to $25 million. Under this agreement, $12.0 million was outstanding at December 31, 2002, and there were no amounts outstanding at December 31, 2001. This subsidiary intends to renew this credit agreement, which expires June 30, 2003.

In order to borrow under the credit facility, the subsidiary must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on sale of assets and limitation on loans and investments. This subsidiary was in compliance with these covenants and met the required conditions at December 31, 2002.

NOTE 8
Long-term Debt and Indenture Provisions

Long-term debt outstanding at December 31 was as follows:

	2002	2001
	(In thousands)	
First mortgage bonds and notes:		
Pollution Control Refunding Revenue Bonds, Series 1992, 6.65%, due June 1, 2022	$ 20,850	$ 20,850
Secured Medium-Term Notes, Series A at a weighted average rate of 7.59%, due on dates ranging from October 1, 2004 to April 1, 2012	110,000	110,000
Total first mortgage bonds and notes	130,850	130,850
Senior notes at a weighted average rate of 6.90%, due on dates ranging from May 4, 2003 to October 30, 2018	549,100	405,200
Commercial paper at a weighted average rate of 1.47%, supported by revolving credit agreements	151,900	219,700
Revolving line of credit, expired December 31, 2002	–	25,000
Term credit agreements at a weighted average rate of 7.08%, due on dates ranging from January 3, 2003 to December 1, 2013	7,873	11,769
Pollution control note obligation, 6.20%, due March 1, 2004	2,000	2,500
Discount	(82)	(225)
Total long-term debt	841,641	794,794
Less current maturities	22,083	11,085
Net long-term debt	$819,558	$783,709

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2002, aggregate $22.1 million in 2003; $173.8 million in 2004; $70.3 million in 2005; $100.2 million in 2006; $105.4 million in 2007 and $369.8 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2002.

MDU Resources Group, Inc.

As discussed in Note 7, MDU Resources has a revolving credit agreement with various banks that supports $50 million of its $75 million commercial paper program.

At December 31, 2001, there was $25.0 million outstanding under a previous revolving line of credit.

MDU Resources' issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Indenture of Mortgage. Generally, those restrictions require MDU Resources to pledge $1.43 of unfunded property to the trustee for each dollar of indebtedness incurred under the Indenture and that annual earnings (pretax and before interest charges), as defined in the Indenture, equal at least two times its annualized first mortgage bond interest costs. Under the more restrictive of the two tests, as of December 31, 2002, MDU Resources could have issued approximately $327 million of additional first mortgage bonds.

Centennial Energy Holdings, Inc.

Centennial has a revolving credit agreement with various banks that supports $305 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreement at December 31, 2002 and 2001. Under the Centennial commercial paper program, $101.9 million and $219.7 million were outstanding at December 31, 2002 and 2001, respectively. The Centennial commercial paper borrowings are classified as long term as Centennial intends to refinance these borrowings on a long-term basis through continued Centennial commercial paper borrowings and as further supported by the Centennial credit agreement, which allows for subsequent borrowings up to a term of one year. Centennial intends to renew the Centennial credit agreement, which expires September 26, 2003.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $400 million. Under the terms of the master shelf agreement, $360.6 million was outstanding at December 31, 2002, and $210.0 million was outstanding at December 31, 2001. The amount outstanding under the uncommitted long-term master shelf agreement is included in senior notes in the preceding long-term debt table.

NOTE 8 (Continued)

In order to borrow under Centennial's credit agreement and the Centennial uncommitted long-term master shelf agreement, Centennial and certain of its subsidiaries must be in compliance with the applicable covenants and certain other conditions. The significant covenants include maximum capitalization ratios, minimum interest coverage ratios, minimum consolidated net worth, limitation on priority debt, limitation on sale of assets and limitation on loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2002.

The Centennial credit agreement and the Centennial uncommitted long-term master shelf agreement contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the Centennial credit agreement and the Centennial uncommitted long-term master shelf agreement will be in default. The Centennial credit agreement, the Centennial uncommitted long-term master shelf agreement and Centennial's practice limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company

Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of the Company, has an uncommitted long-term master shelf agreement that allows for borrowings of up to $100 million. Under the terms of the master shelf agreement, $30.0 million was outstanding at December 31, 2002.

In order to borrow under Williston Basin's uncommitted long-term master shelf agreement, it must be in compliance with the applicable covenants and certain other conditions. The significant covenants include limitation on consolidated indebtedness, limitation on priority debt, limitation on sale of assets and limitation on investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2002.

NOTE 9 Preferred Stocks

Preferred stocks at December 31 were as follows:

	2002	2001
	(Dollars in thousands)	
Authorized:		
Preferred –		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A –		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference –		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption –		
Preferred –		
5.10% Series – 13,000 shares in 2002 and 14,000 shares in 2001	$ 1,300	$ 1,400
Other preferred stock –		
4.50% Series – 100,000 shares	10,000	10,000
4.70% Series – 50,000 shares	5,000	5,000
	15,000	15,000
Total preferred stocks	16,300	16,400
Less sinking fund requirements	100	100
Net preferred stocks	$16,200	$16,300

The preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date on certain series of preferred stock.

The Company is obligated to make annual sinking fund contributions to retire the 5.10% Series preferred stock. The redemption prices and sinking fund requirements, where applicable, are summarized below:

Series	Redemption Price *(a)*	Sinking Fund Shares	Sinking Fund Price *(a)*
Preferred stocks:			
4.50%	$105 *(b)*	–	–
4.70%	$102 *(b)*	–	–
5.10%	$102	1,000 *(c)*	$100

(a) Plus accrued dividends.
(b) These series are redeemable at the sole discretion of the Company.
(c) Annually on December 1, if tendered.

In the event of a voluntary or involuntary liquidation, all preferred stock series holders are entitled to $100 per share, plus accrued dividends.

The aggregate annual sinking fund amount applicable to preferred stock subject to mandatory redemption is $100,000 for each of the five years following December 31, 2002, and $800,000 thereafter.

NOTE 10 Common Stock

At the Annual Meeting of Stockholders held on April 23, 2002, the Company's common stockholders approved an amendment to the Certificate of Incorporation increasing the authorized number of common shares from 150 million shares to 250 million shares with a par value of $1.00 per share.

The Company's Automatic Dividend Reinvestment and Stock Purchase Plan (Stock Purchase Plan) provides participants the opportunity to invest all or a portion of their cash dividends in shares of the Company's common stock and to make optional cash payments for the same purpose. Holders of all classes of the Company's capital stock; legal residents in any of the 50 states; and beneficial owners, whose shares are held by brokers or other nominees through participation by their brokers or nominees, are eligible to participate in the Stock Purchase Plan. The Company's 401(k) Retirement Plan (K-Plan), is partially funded with the Company's common stock. Since January 1, 2000, the Stock Purchase Plan and K-Plan, with respect to Company stock, have been funded by the purchase of shares of common stock on the open market. At December 31, 2002, there were 8.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

In November 1998, the Company's Board of Directors declared, pursuant to a stockholders' rights plan, a dividend of one preference share purchase right (right) for each outstanding share of the Company's common stock. Each right becomes exercisable, upon the occurrence of certain events, for one one-thousandth of a share of Series B Preference Stock of the Company, without par value, at an exercise price of $125 per one one-thousandth, subject to certain adjustments. The rights are currently not exercisable and will be exercisable only if a person or group (acquiring person) either acquires ownership of 15 percent or more of the Company's common stock or commences a tender or exchange offer that would result in ownership of 15 percent or more. In the event the Company is acquired in a merger or other business combination transaction or 50 percent or more of its consolidated assets or earnings power are sold, each right entitles the holder to receive, upon the exercise thereof at the then current exercise price of the right multiplied by the number of one one-thousandth of a Series B Preference Stock for which a right is then exercisable, in accordance with the terms of the rights agreement, such number of shares of common stock of the acquiring person having a market value of twice the then current exercise price of the right. The rights, which expire on December 31, 2008, are redeemable in whole, but not in part, for a price of $.01 per right, at the Company's option at any time until any acquiring person has acquired 15 percent or more of the Company's common stock.

The Company has stock option plans for directors, key employees and employees, that grant options to purchase shares of the Company's stock. The Company accounts for these option plans in accordance with APB Opinion No. 25 under which no compensation expense has been recognized. The option exercise price is the market value of the stock on the date of grant. Options granted to the key employees automatically vest after nine years, but the plan provides for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expire 10 years after the date of grant. Options granted to directors and employees vest at date of grant and three years after date of grant, respectively, and expire 10 years after the date of grant. In addition, the Company has granted restricted stock awards under a long-term incentive plan, deferred compensation agreements and a restricted stock agreement totaling 350,392 shares and 348,021 shares in 2001 and 2000, respectively.

NOTE 10 (Continued)

The restricted stock awards granted vest to the participants at various times ranging from two years to nine years from date of issuance, but certain grants may vest early based upon the attainment of certain performance goals or upon a change in control of the Company. The weighted average grant date fair value of the restricted stock grants was $31.55 and $20.81 in 2001 and 2000, respectively. The Company also has granted stock awards totaling 14,260 shares, 12,673 shares and 7,582 shares in 2002, 2001 and 2000, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $28.80, $30.14 and $22.98, in 2002, 2001 and 2000, respectively. Nonemployee directors may receive shares of common stock instead of cash in payment for director's fees under the nonemployee director stock compensation plan. Compensation expense recognized for restricted stock grants and stock grants was $5.2 million, $4.9 million and $1.8 million in 2002, 2001 and 2000, respectively. The Company is authorized to grant options, restricted stock and stock for up to 10.0 million shares of common stock and has granted options, restricted stock and stock on 4.7 million shares through December 31, 2002.

For a discussion of the effect on earnings and earnings per common share for the years ended December 31, 2002, 2001 and 2000, if the Company had applied SFAS No. 123, see Note 1.

A summary of the status of the stock option plans at December 31, 2002, 2001 and 2000, and changes during the years then ended was as follows:

	2002		2001		2000	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	3,472,207	$27.90	1,224,959	$20.61	1,427,262	$19.46
Granted	107,070	28.72	2,693,120	30.14	74,000	20.54
Forfeited	(302,560)	29.66	(74,282)	27.24	(84,135)	21.18
Exercised	(35,872)	18.30	(371,590)	20.23	(192,168)	11.84
Balance at end of year	3,240,845	27.87	3,472,207	27.90	1,224,959	20.61
Exercisable at end of year	756,700	$21.84	770,142	$21.41	129,763	$18.11

Summarized information about stock options outstanding and exercisable as of December 31, 2002, was as follows:

	Options Outstanding			Options Exercisable	
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$12.33 – 17.50	28,374	2.9	$13.62	28,374	$13.62
17.51 – 24.50	762,521	5.3	21.14	671,326	21.14
24.51 – 31.50	2,301,910	8.2	29.69	27,000	29.32
31.51 – 38.55	148,040	8.2	36.87	30,000	38.55
Balance at end of year	3,240,845	7.4	27.87	756,700	21.84

The fair value of each option is estimated on the date of grant using the Black-Scholes option pricing model. The weighted average fair value of the options granted and the assumptions used to estimate the fair value of options were as follows:

	2002	2001	2000
Weighted average fair value of options at grant date	$8.07	$7.38	$5.07
Weighted average risk-free interest rate	5.14%	5.19%	6.76%
Weighted average expected price volatility	30.80%	26.05%	23.55%
Weighted average expected dividend yield	3.43%	3.53%	3.84%
Expected life in years	7	7	7

NOTE 11 Income Taxes

Income tax expense for the years ended December 31 was as follows:

	2002	2001	2000
		(In thousands)	
Current:			
Federal	$46,389	$66,211	$27,865
State	9,082	11,160	5,188
Foreign	–	(44)	67
	55,471	77,327	33,120
Deferred:			
Income taxes –			
Federal	26,373	16,972	29,323
State	4,632	4,773	8,060
Foreign	338	–	–
Investment tax credit	(584)	(731)	(853)
	30,759	21,014	36,530
Total income tax expense	$86,230	$98,341	$69,650

Components of deferred tax assets and deferred tax liabilities recognized at December 31 were as follows:

	2002	2001
	(In thousands)	
Deferred tax assets:		
Accrued pension costs	$ 12,112	$ 9,349
Regulatory matters	11,644	21,000
Deferred compensation	3,991	2,386
Bad debts	2,798	1,774
Deferred investment tax credit	1,185	1,413
Accrued land reclamation	263	1,648
Other	20,848	17,531
Total deferred tax assets	52,841	55,101
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	331,694	302,103
Basis differences on natural gas and oil producing properties	70,464	61,684
Regulatory matters	5,491	5,661
Other	10,412	9,092
Total deferred tax liabilities	418,061	378,540
Net deferred income tax liability	$(365,220)	$(323,439)

As of December 31, 2002 and 2001, no valuation allowance has been recorded associated with the above deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2001, to December 31, 2002, to deferred income tax expense:

	2002
	(In thousands)
Net change in deferred income tax liability from the preceding table	$ 41,781
Deferred taxes associated with acquisitions	(17,217)
Deferred taxes associated with other comprehensive loss	7,227
Other	(1,032)
Deferred income tax expense for the period	$ 30,759

NOTE 11 (Continued)

Total income tax expense differs from the amount computed by applying the statutory federal income tax rate to income before taxes. The reasons for this difference were as follows:

Years ended December 31,	2002		2001		2000	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$82,136	35.0	$88,966	35.0	$63,237	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	10,279	4.4	11,311	4.5	8,044	4.4
Investment tax credit amortization	(584)	(.3)	(731)	(.3)	(853)	(.5)
Depletion allowance	(2,200)	(.9)	(1,820)	(.7)	(1,631)	(.9)
Other items	(3,401)	(1.5)	615	.2	853	.5
Total income tax expense	$86,230	36.7	$98,341	38.7	$69,650	38.5

The Company considers earnings from its foreign equity method investment in a natural gas-fired electric generation facility in Brazil to be reinvested indefinitely outside of the United States and, accordingly, no U.S. deferred income taxes are recorded with respect to such earnings. Should the earnings be remitted as dividends, the Company may be subject to additional U.S. taxes, net of allowable foreign tax credits.

NOTE 12 Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. Prior to the fourth quarter of 2002, the Company reported six business segments consisting of electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production and construction materials and mining. During the fourth quarter of 2002, the Company added an additional segment, independent power production, based on the significance of this segment's operations. Substantially all of the operations of the independent power production segment began in 2002, therefore financial information for years prior to 2002 has not been presented.

The Company's operations are now conducted through seven business segments. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which consists largely of an investment in a natural gas-fired electric generation station in Brazil as discussed in Note 2. The electric segment generates, transmits and distributes electricity and the natural gas distribution segment distributes natural gas. These operations also supply related value-added products and services in the northern Great Plains. The utility services segment consists of a diversified infrastructure company specializing in electric, gas and telecommunication utility construction, as well as industrial and commercial electrical, exterior lighting and traffic signalization throughout most of the United States. Utility services also provides related specialty equipment manufacturing, sales and rental services. The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. The pipeline and energy services segment also provides energy-related management services, including cable and pipeline magnetization and locating. The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration and production activities primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico. The construction materials and mining segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt and other value-added products, as well as performing integrated construction services, in the north central and western United States, including Alaska and Hawaii. The independent power production segment owns electric generating facilities in the United States and Brazil. Electric capacity and energy produced at these facilities is sold under long-term contracts to nonaffiliated entities. This segment also invests in potential new growth and synergistic opportunities that are not directly being pursued by other business segments.

In 2001, the Company sold its coal operations to Westmoreland Coal Company for $28.2 million in cash, including final settlement cost adjustments. The sale of the coal operations was effective April 30, 2001. Included in the sale were active coal mines in North Dakota and Montana, coal sales agreements, reserves and mining equipment, and certain development rights at the former Gascoyne Mine site in North Dakota. The Company retains ownership of coal reserves and leases at its former Gascoyne Mine site. Including final settlement cost adjustments, the Company recorded a gain of $10.3 million ($6.2 million after tax) included in other income – net from the sale in 2001.

Segment information follows the same accounting policies as described in the Summary of Significant Accounting Policies. Segment information as of December 31 and for the years then ended was as follows:

	2002	2001	2000
		(In thousands)	
External operating revenues:			
Electric	$ 162,616	$ 168,837	$ 161,621
Natural gas distribution	186,569	255,389	233,051
Utility services	458,660	364,746	169,382
Pipeline and energy services	110,224	479,108	579,207
Natural gas and oil production	148,158	148,653	99,014
Construction materials and mining	962,312	801,883	617,564
Independent power production	2,998	–	–
Total external operating revenues	$2,031,537	$2,218,616	$1,859,839
Intersegment operating revenues:			
Electric	$ –	$ –	$ –
Natural gas distribution	–	–	–
Utility services	–	4	–
Pipeline and energy services	55,034	52,006	57,641
Natural gas and oil production	55,437	61,178	39,302
Construction materials and mining	–	5,016 *(a)*	13,832 *(a)*
Independent power production	3,778	–	–
Intersegment eliminations	(114,249)	(113,188)	(96,943)
Total intersegment operating revenues	$ –	$ 5,016 *(a)*	$ 13,832 *(a)*
Depreciation, depletion and amortization:			
Electric	$ 19,537	$ 19,488	$ 19,115
Natural gas distribution	9,940	9,337	8,399
Utility services	9,871	8,395	4,912
Pipeline and energy services	14,846	14,341	15,301
Natural gas and oil production	48,714	41,690	27,008
Construction materials and mining	54,334	46,666	36,153
Independent power production	719	–	–
Total depreciation, depletion and amortization	$ 157,961	$ 139,917	$ 110,888
Interest expense:			
Electric	$ 7,621	$ 8,531	$ 10,007
Natural gas distribution	4,364	3,727	4,142
Utility services	3,568	3,807	2,492
Pipeline and energy services	7,670	9,136	10,029
Natural gas and oil production	2,464	1,359	5,160
Construction materials and mining	18,422	19,339	16,415
Independent power production	1,122	–	–
Intersegment eliminations	(216)	–	(212)
Total interest expense	$ 45,015	$ 45,899	$ 48,033
Income taxes:			
Electric	$ 9,501	$ 10,511	$ 10,048
Natural gas distribution	(1,325)	1,067	3,544
Utility services	4,781	9,131	6,027
Pipeline and energy services	12,462	11,633	9,214
Natural gas and oil production	30,604	40,486	23,906
Construction materials and mining	29,415	25,513	16,911
Independent power production	792	–	–
Total income taxes	$ 86,230	$ 98,341	$ 69,650

NOTE 12 (Continued)

	2002	2001	2000
		(In thousands)	
Earnings on common stock:			
Electric	$ 15,780	$ 18,717	$ 17,733
Natural gas distribution	3,587	677	4,741
Utility services	6,371	12,910	8,607
Pipeline and energy services	19,097	16,406	10,494
Natural gas and oil production	53,192	63,178	38,574
Construction materials and mining	48,702	43,199	30,113
Independent power production	959	–	–
Total earnings on common stock	$ 147,688	$ 155,087	$ 110,262
Capital expenditures:			
Electric	$ 27,795	$ 14,373	$ 15,788
Natural gas distribution	11,044	14,685	21,336
Utility services	17,242	70,232	42,633
Pipeline and energy services	21,449	51,054	69,006
Natural gas and oil production	136,424	118,719	173,441
Construction materials and mining	106,893	170,585	218,716
Independent power production	95,748	–	–
Net proceeds from sale or disposition of property	(16,217)	(51,641)	(11,000)
Total net capital expenditures	$ 400,378	$ 388,007	$ 529,920
Identifiable assets:			
Electric *(b)*	$ 310,519	$ 291,229	$ 305,099
Natural gas distribution *(b)*	170,672	182,705	192,854
Utility services	230,888	239,069	123,451
Pipeline and energy services	302,972	346,879	362,592
Natural gas and oil production	554,420	476,105	410,207
Construction materials and mining	1,137,697	1,035,929	874,299
Independent power production	148,770	–	–
Corporate assets *(c)*	81,311	51,155	44,457
Total identifiable assets	$2,937,249	$2,623,071	$2,312,959
Property, plant and equipment:			
Electric *(b)*	$ 619,230	$ 597,080	$ 589,700
Natural gas distribution *(b)*	246,844	238,566	227,742
Utility services	70,660	59,190	39,865
Pipeline and energy services	412,694	410,049	369,834
Natural gas and oil production	755,788	630,826	513,419
Construction materials and mining	804,255	711,410	653,189
Independent power production	94,525	–	–
Less accumulated depreciation, depletion and amortization	1,079,110	942,723	891,228
Net property, plant and equipment	$1,924,886	$1,704,398	$1,502,521

(a) In accordance with the provision of SFAS No. 71, intercompany coal sales were not eliminated.

(b) Includes, in the case of electric and natural gas distribution property, allocations of common utility property.

(c) Corporate assets consist of assets not directly assignable to a business segment (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).

Capital expenditures for 2002, 2001 and 2000, related to acquisitions, in the preceding table included the following noncash transactions: issuance of the Company's equity securities of $47.2 million in 2002; issuance of the Company's equity securities of $57.4 million in 2001; and issuance of the Company's equity securities and the conversion of a note receivable to purchase consideration of $132.1 million in 2000.

NOTE 13 Acquisitions

In 2002, the Company acquired a number of businesses, none of which was individually material, including utility services companies in California and Ohio, construction materials and mining businesses in Minnesota and Montana, an energy development company in Montana and natural gas-fired electric generating facilities in Colorado. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $139.8 million.

In 2001, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Minnesota and Oregon; utility services businesses based in Missouri and Oregon; and an energy services company specializing in cable and pipeline locating and tracking systems. The total purchase consideration for these businesses, consisting of the Company's common stock and cash, was $170.1 million.

In 2000, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses with operations in Alaska, California, Montana and Oregon; a coalbed natural gas development operation based in Colorado with related oil and gas leases and properties in Montana and Wyoming; utility services businesses based in California, Colorado, Montana and Ohio; a natural gas distribution business serving southeastern North Dakota and western Minnesota; and an energy services company based in Texas. The total purchase consideration for these businesses, consisting of the Company's common stock, cash and the conversion of a note receivable to purchase consideration, was $286.0 million.

On April 1, 2000, Fidelity Exploration & Production Company (Fidelity), an indirect wholly owned subsidiary of the Company, purchased substantially all of the assets of Preston Reynolds & Co., Inc. (Preston), a coalbed natural gas development operation, as previously discussed. Pursuant to the asset purchase and sale agreement, Preston could, but was not obligated to purchase, acquire and own an undivided 25 percent working interest (Seller's Option Interest) in certain oil and gas leases or properties acquired and/or generated by Fidelity. Fidelity had the right, but not the obligation, to purchase Seller's Option Interest from Preston for an amount as specified in the agreement. On July 10, 2002, Fidelity purchased the Seller's Option Interest.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been preliminarily recorded at their respective fair values as of the date of acquisition. Final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date on certain of the above acquisitions made in 2002. The results of operations of the acquired businesses are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the above acquisitions are not presented as such acquisitions were not material to the Company's financial position or results of operations.

NOTE 14 Employee Benefit Plans

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans. Changes in benefit obligation and plan assets for the years ended December 31 and amounts recognized in the Consolidated Balance Sheets at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$204,046	$200,880	$67,019	$69,467
Service cost	5,135	4,716	1,460	1,376
Interest cost	14,877	14,498	4,915	4,691
Plan participants' contributions	–	–	834	866
Amendments	372	(1,342)	–	–
Actuarial (gain) loss	12,324	8,128	5,678	(2,109)
Divestiture*	–	(10,017)	–	(2,871)
Benefits paid	(11,988)	(12,817)	(4,989)	(4,401)
Benefit obligation at end of year	224,766	204,046	74,917	67,019
Change in plan assets:				
Fair value of plan assets at beginning of year	224,667	261,864	45,175	47,046
Actual loss on plan assets	(26,543)	(13,828)	(4,196)	(2,235)
Employer contribution	3,007	337	4,065	3,899
Plan participants' contributions	–	–	834	866
Divestiture*	–	(10,889)	–	–
Benefits paid	(11,988)	(12,817)	(4,989)	(4,401)
Fair value of plan assets at end of year	189,143	224,667	40,889	45,175
Funded status – over (under)	(35,623)	20,621	(34,028)	(21,844)
Unrecognized actuarial (gain) loss	35,662	(26,170)	3,484	(10,799)
Unrecognized prior service cost	9,501	10,278	–	–
Unrecognized net transition obligation (asset)	(1,247)	(2,195)	21,513	23,665
Prepaid (accrued) benefit cost	8,293	2,534	(9,031)	(8,978)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	16,175	11,867	–	–
Accrued benefit liability	(7,882)	(9,333)	(9,031)	(8,978)
Additional minimum liability	(4,905)	–	–	–
Intangible asset	533	–	–	–
Accumulated other comprehensive loss	4,372	–	–	–
Net amount recognized	$ 8,293	$ 2,534	$ (9,031)	$ (8,978)

*See Note 12 for more information on the sale of the Company's coal operations.

Weighted average assumptions for the Company's pension and other postretirement benefit plans as of December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2002	2001	2002	2001
Discount rate	6.75%	7.25%	6.75%	7.25%
Expected return on plan assets	8.50%	8.50%	7.50%	7.50%
Rate of compensation increase	4.50%	5.00%	4.50%	5.00%

Health care rate assumptions for the Company's other postretirement benefit plans as of December 31 were as follows:

	2002	2001
Health care trend rate	6.00%-11.00%	6.00%-11.00%
Health care cost trend rate – ultimate	5.00%-6.00%	5.00%-6.00%
Year in which ultimate trend rate achieved	1999-2011	1999-2010

Components of net periodic benefit expense (income) for the Company's pension and other postretirement benefit plans were as follows:

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	2002	2001	2000	2002	2001	2000
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$ 5,135	$ 4,716	$ 4,561	$ 1,460	$ 1,376	$ 1,307
Interest cost	14,877	14,498	14,174	4,915	4,691	4,946
Expected return on assets	(21,110)	(20,672)	(19,927)	(3,843)	(3,619)	(3,267)
Amortization of prior service cost	1,148	1,247	1,047	–	–	–
Recognized net actuarial gain	(1,855)	(2,687)	(2,907)	(566)	(930)	(799)
Settlement (gain) loss	–	(884)	(700)	–	15	–
Amortization of net transition obligation (asset)	(947)	(965)	(997)	2,151	2,227	2,378
Net periodic benefit cost (income)	(2,752)	(4,747)	(4,749)	4,117	3,760	4,565
Less amount capitalized	(352)	(391)	(397)	404	329	369
Net periodic benefit expense (income)	$ (2,400)	$ (4,356)	$ (4,352)	$ 3,713	$ 3,431	$ 4,196

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets, for the pension plans with accumulated benefit obligations in excess of plan assets, were $22.1 million, $19.6 million and $17.3 million, respectively, as of December 31, 2002. As a result of the accumulated benefit obligations exceeding the fair value of plan assets for these plans, an additional minimum liability of $4.9 million was recognized in 2002. The additional minimum liability also reflects the amount of prepaid benefit cost or accrued benefit liability related to these plans.

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

NOTE 14 (Continued)

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have the following effects at December 31, 2002:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 232	$ (841)
Effect on postretirement benefit obligation	$3,062	$(8,076)

In addition to company-sponsored plans, certain employees are covered under multi-employer defined benefit plans administered by a union. Amounts contributed to the multi-employer plans were $27.8 million, $19.9 million and $10.6 million in 2002, 2001 and 2000, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this footnote, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that provides for defined benefit payments upon the employee's retirement or to their beneficiaries upon death for a 15-year period or as an equivalent life annuity. Investments consist of life insurance carried on plan participants, which is payable to the Company upon the employee's death. The cost of these benefits was $5.1 million, $4.3 million and $3.5 million in 2002, 2001 and 2000, respectively. The total projected obligation for this plan was $40.5 million and $41.0 million at December 31, 2002 and 2001, respectively. The additional minimum liability relating to this plan was $4.0 million at December 31, 2002. The Company has a related intangible asset recognized as of December 31, 2002, of $1.1 million. The actuarial valuations for this plan were determined based on a discount rate of 6.75 percent and 7.25 percent as of December 31, 2002 and 2001, respectively, and a rate of compensation increase of 4.50 percent and 5.00 percent as of December 31, 2002 and 2001, respectively.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $9.6 million in 2002, $7.2 million in 2001 and $6.1 million in 2000. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 15 Jointly Owned Facilities

The consolidated financial statements include the Company's 22.7 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station and the Coyote Station, respectively. Each owner of the Big Stone and Coyote stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the Big Stone Station and Coyote Station operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2002	2001
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 53,018	$ 50,053
Less accumulated depreciation	34,456	32,956
	$ 18,562	$ 17,097
Coyote Station:		
Utility plant in service	$122,476	$122,436
Less accumulated depreciation	70,778	67,414
	$ 51,698	$ 55,022

NOTE 16 Regulatory Matters and Revenues Subject To Refund

On December 30, 2002, Montana-Dakota Utilities Co. (Montana-Dakota), a public utility division of MDU Resources, filed an application with the South Dakota Public Utilities Commission (SDPUC) for a natural gas rate increase. Montana-Dakota requested a total of $2.2 million annually or 5.8 percent above current rates. A final order from the SDPUC is due June 30, 2003.

On October 7, 2002, Great Plains Natural Gas Co. (Great Plains), a public utility division of MDU Resources, filed an application with the Minnesota Public Utilities Commission (MPUC) for a natural gas rate increase. Great Plains requested a total of $1.6 million annually or 6.9 percent above current rates. On December 4, 2002, the MPUC issued an Order setting interim rates that approved an interim increase of $1.4 million annually effective December 6, 2002. Great Plains began collecting such rates effective December 6, 2002, subject to refund until the MPUC issues a final order. A final order from the MPUC is due August 22, 2003.

On June 10, 2002, Montana-Dakota filed an application with the Wyoming Public Service Commission (WYPSC) for a natural gas rate increase. Montana-Dakota requested a total of $662,000 annually or 5.6 percent above current rates. On December 9, 2002, the WYPSC approved an increase of $466,000 annually effective January 1, 2003.

On May 20, 2002, Montana-Dakota filed an application with the Montana Public Service Commission (MTPSC) for a natural gas rate increase. Montana-Dakota requested a total of $3.6 million annually or 6.5 percent above current rates. On September 5, 2002, the MTPSC approved an interim increase of $2.1 million annually, effective with service rendered on and after September 5, 2002. Montana-Dakota began collecting such rates effective September 5, 2002, which are subject to refund until the MTPSC issues a final order. On November 7, 2002, the MTPSC approved an additional interim increase of $300,000 annually effective November 15, 2002. The additional interim increase is the result of a Stipulation reached between Montana-Dakota and the Montana Consumer Counsel, the only intervener in the proceeding. Under the terms of the Stipulation, the total interim relief granted ($2.4 million) will be the final increase in the proceeding. A hearing before the MTPSC was held on December 6, 2002, at which the MTPSC took under advisement the Stipulation agreed upon by Montana-Dakota and the Montana Consumer Counsel. A final order from the MTPSC is due February 20, 2003.

On April 12, 2002, Montana-Dakota filed an application with the North Dakota Public Service Commission (NDPSC) for a natural gas rate increase. Montana-Dakota requested a total of $2.8 million annually or 4.1 percent above current rates. On December 10, 2002, the NDPSC approved an increase of $2.0 million annually, effective with service rendered on or after December 12, 2002.

Reserves have been provided for a portion of the revenues that have been collected subject to refund for certain of the above proceedings. The Company believes that such reserves are adequate based on its assessment of the ultimate outcome of the proceedings.

The NDPSC authorized its Staff to initiate an investigation into the earnings levels of Montana-Dakota's North Dakota electric operations based on Montana-Dakota's 2000 Annual Report to the NDPSC. The investigation was based on a complaint filed with the NDPSC in September 2001, by the NDPSC Staff. On April 24, 2002, the NDPSC issued an Order requiring Montana-Dakota to reduce its North Dakota electric rates by $4.3 million annually, effective May 8, 2002. On April 25, 2002, Montana-Dakota filed an appeal of the NDPSC Order in the North Dakota South Central Judicial District Court (District Court). The filing also requested a stay of the effectiveness of the NDPSC Order while the appeal was pending. Montana-Dakota challenged the NDPSC's determination of the level of wholesale electricity sales margins expected to be received by Montana-Dakota. On May 2, 2002, the District Court granted Montana-Dakota's request for a stay of a portion of the $4.3 million annual rate reduction ordered by the NDPSC. Accordingly, Montana-Dakota implemented an annual rate reduction of $800,000 effective with service rendered on and after May 8, 2002, rather than the $4.3 million annual reduction ordered by the NDPSC. The remaining $3.5 million was subject to refund if Montana-Dakota did not prevail in this proceeding. On November 22, 2002, the District Court issued an Order reversing the decision of the NDPSC and remanded the case back to the NDPSC. On January 15, 2003, the NDPSC issued an Order accepting Montana-Dakota's level of wholesale electricity sales margins thus reversing its initial decision and allowing Montana-Dakota to continue to charge the electric rates which were in effect.

Montana-Dakota had established reserves for 2002 revenues that had been collected subject to refund with respect to Montana-Dakota's pending electric rate reduction. Based on the January 15, 2003, Order, as previously discussed, the reserves were reversed and recognized in income in 2002.

NOTE 16 (Continued)

In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. Williston Basin began collecting such rates effective June 1, 2000, subject to refund. In May 2001, the Administrative Law Judge issued an Initial Decision on Williston Basin's natural gas rate change application. This matter is currently pending before and subject to revision by the FERC.

Reserves have been provided for a portion of the revenues that have been collected subject to refund with respect to Williston Basin's pending regulatory proceeding. Williston Basin, in the fourth quarter of 2000, determined that reserves it had previously established for certain regulatory proceedings, prior to the proceeding filed in 1999, exceeded its expected refund obligation and, accordingly, reversed reserves and recognized in income $6.7 million after tax. Williston Basin believes that its remaining reserves are adequate based on its assessment of the ultimate outcome of the application filed in December 1999.

NOTE 17 Commitments and Contingencies

Litigation

In January 2002, Fidelity Oil Co. (FOC), one of the Company's natural gas and oil production subsidiaries, entered into a compromise agreement with the former operator of certain of FOC's oil production properties in southeastern Montana. The compromise agreement resolved litigation involving the interpretation and application of contractual provisions regarding net proceeds interests paid by the former operator to FOC for a number of years prior to 1998. The terms of the compromise agreement are confidential. As a result of the compromise agreement, the natural gas and oil production segment reflected a nonrecurring gain in its financial results for the first quarter of 2002 of approximately $16.6 million after tax. As part of the settlement, FOC gave the former operator a full and complete release, and FOC is not asserting any such claim against the former operator for periods after 1997.

In July 1996, Jack J. Grynberg (Grynberg) filed suit in United States District Court for the District of Columbia (U.S. District Court) against Williston Basin and over 70 other natural gas pipeline companies. Grynberg, acting on behalf of the United States under the Federal False Claims Act, alleged improper measurement of the heating content and volume of natural gas purchased by the defendants resulting in the underpayment of royalties to the United States. In March 1997, the U.S. District Court dismissed the suit without prejudice and the dismissal was affirmed by the United States Court of Appeals for the D.C. Circuit in October 1998. In June 1997, Grynberg filed a similar Federal False Claims Act suit against Williston Basin and Montana-Dakota and filed over 70 other separate similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. In April 1999, the United States Department of Justice decided not to intervene in these cases. In response to a motion filed by Grynberg, the Judicial Panel on Multidistrict Litigation consolidated all of these cases in the Federal District Court of Wyoming (Federal District Court). Oral argument on motions to dismiss was held before the Federal District Court in March 2000. In May 2001, the Federal District Court denied Williston Basin's and Montana-Dakota's motion to dismiss. The matter is currently pending.

The Quinque Operating Company (Quinque), on behalf of itself and subclasses of gas producers, royalty owners and state taxing authorities, instituted a legal proceeding in State District Court for Stevens County, Kansas, (State District Court) against over 200 natural gas transmission companies and producers, gatherers, and processors of natural gas, including Williston Basin and Montana-Dakota. The complaint, which was served on Williston Basin and Montana-Dakota in September 1999, contains allegations of improper measurement of the heating content and volume of all natural gas measured by the defendants other than natural gas produced from federal lands. In response to a motion filed by the defendants in this suit, the Judicial Panel on Multidistrict Litigation transferred the suit to the Federal District Court for inclusion in the pretrial proceedings of the Grynberg suit. Upon motion of plaintiffs, the case has been remanded to State District Court. In September 2001, the defendants in this suit filed a motion to dismiss with the State District Court. The motion to dismiss was denied by the State District Court on August 19, 2002. The matter is currently pending.

Williston Basin and Montana-Dakota believe the claims of Grynberg and Quinque are without merit and intend to vigorously contest these suits. Williston Basin and Montana-Dakota believe it is not probable that Grynberg and Quinque will ultimately succeed given the current status of the litigation.

The Company is also involved in other legal actions in the ordinary course of its business. Although the outcomes of any such legal actions cannot be predicted, management believes that the outcomes with respect to these other legal proceedings will not have a material adverse effect upon the Company's financial position or results of operations.

Environmental matters

In December 2000, Morse Bros., Inc. (MBI), an indirect wholly owned subsidiary of the Company, was named by the United States Environmental Protection Agency (EPA) as a Potentially Responsible Party in connection with the cleanup of a commercial property site, now owned by MBI, and part of the Portland, Oregon, Harbor Superfund Site. Sixty-eight other parties were also named in this administrative action. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon State Department of Environmental Quality and other information available, MBI does not believe it is a Responsible Party. In addition, MBI intends to seek indemnity for any and all liabilities incurred in relation to the above matters from Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, pursuant to the terms of their sale agreement.

The Company believes it is not probable that it will incur any material environmental remediation costs or damages in relation to the above administrative action.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2002, were $19.3 million in 2003, $14.3 million in 2004, $11.2 million in 2005, $7.8 million in 2006, $4.3 million in 2007 and $21.3 million thereafter. Rent expense related to operating leases was approximately $26.9 million, $31.5 million and $23.7 million for the years ended December 31, 2002, 2001 and 2000, respectively.

Purchase commitments

The Company has entered into various commitments, largely purchased power, coal and natural gas supply, electric generation construction and natural gas transportation contracts. These commitments range from one to 18 years. The commitments under these contracts as of December 31, 2002, were $171.3 million in 2003, $55.4 million in 2004, $43.1 million in 2005, $37.0 million in 2006, $27.6 million in 2007 and $130.4 million thereafter. These commitments are not reflected in the Company's consolidated financial statements.

Guarantees

Centennial has guaranteed, with the right of subrogation, a portion of certain obligations of MPX in connection with the Company's equity method investment in the natural gas-fired electric generation station in Brazil, as discussed in Note 2. The Company, through a subsidiary, owns 49 percent of MPX. These guarantees expire in 2003, and at December 31, 2002, the maximum amounts outstanding under these guarantees totaled $24.9 million. In the event MPX defaults under its obligations, Centennial would be required to make payments under these guarantees. These guarantees are not reflected on the Consolidated Balance Sheets.

In addition, Centennial has guaranteed, without recourse, the short-term line of credit agreement of a subsidiary of the Company as discussed in Note 7. The proceeds from the short-term line of credit were used in connection with the Company's investment in international projects. The fixed maximum amount of Centennial's guarantee of this line of credit is $25 million and the amount outstanding under this line of credit at December 31, 2002, was $12.0 million, which amount is reflected on the Consolidated Balance Sheets. This subsidiary of the Company intends to renew this credit agreement, which expires June 30, 2003. In the event this subsidiary of the Company defaults under its obligation, Centennial would be required to make payments under its guarantee.

Centennial has guaranteed, without recourse, a foreign currency collar agreement obligation of an indirect wholly owned subsidiary of the Company. There is no fixed maximum amount guaranteed under the foreign currency collar agreement. The Company recorded an asset for the fair value of the foreign currency collar agreement at December 31, 2002, of $903,000, therefore there was no outstanding obligation guaranteed at December 31, 2002. The foreign currency collar agreement expires on February 3, 2003. In addition, WBI Holdings, Inc. (WBI Holdings), an indirect wholly owned subsidiary of the Company, has guaranteed, without recourse, certain of its subsidiary's natural gas and oil price swap and collar agreement obligations. The amount of the subsidiary's obligation at December 31, 2002, was $4.2 million. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements; however, the amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil price swap and collar agreements expire in December 2003; however, WBI Holdings anticipates continued hedging activities by its subsidiary, and, as a result, will likely issue additional guarantees on potential hedging obligations.

NOTE 17 (Continued)

The amounts outstanding under the natural gas and oil price swap and collar agreements were reflected on the Consolidated Balance Sheets. In the event the above subsidiaries default under their obligations, Centennial and WBI Holdings would be required to make payments under their respective guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company that are related to natural gas transportation and sales agreements, electric power supply agreements and certain other guarantees. These guarantees are without recourse and at December 31, 2002, the fixed maximum amounts guaranteed under these agreements aggregated $55.8 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $29.0 million in 2003; $1.4 million in 2004; $20.0 million in 2009; $2.0 million, which is subject to expiration 30 days after the receipt of written notice; $425,000, which expires upon completion of a guaranteed project and $3.0 million, which has no scheduled maturity date. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantees. Any amounts outstanding by subsidiaries of the Company under the above guarantees were reflected on the Consolidated Balance Sheets at December 31, 2002.

In addition, Centennial has issued guarantees related to the Company's purchase of maintenance items to third parties for which no fixed maximum amounts have been specified. These guarantees are without recourse and have no scheduled maturity date. In the event a subsidiary of the Company defaults under its obligation in relation to the purchase of certain maintenance items, Centennial would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for maintenance were reflected on the Consolidated Balance Sheets at December 31, 2002.

As of December 31, 2002, Centennial was contingently liable for performance of certain of its subsidiaries under approximately $200 million of surety bonds. These bonds are principally for construction contracts and reclamation obligations of these subsidiaries, entered into in the normal course of business. Centennial indemnifies the respective surety bond companies against any exposure under the bonds. A large portion of these contingent commitments expire in 2003, however Centennial will likely continue to enter into surety bonds for its subsidiaries in the future.

Centennial has also guaranteed a wholly owned subsidiary's payment to a third party of the $102.5 million acquisition price in connection with the acquisition of the 66.6-megawatt wind-powered electric generation facility in California. The guarantee will terminate upon the occurrence of the closing of the purchase of the above facility and is without recourse. For more information on the purchase of this facility, see Note 19.

NOTE 18 Inability to Obtain Consent of Prior Independent Public Accountants

There may be risks and stockholders' recovery may be limited as a result of the Company's prior use of Arthur Andersen LLP as the Company's independent public accounting firm. On June 15, 2002, Arthur Andersen LLP was convicted for obstruction of justice charges. Arthur Andersen LLP audited the Company's financial statements for the years ended December 31, 2001 and 2000. On February 14, 2002, Arthur Andersen LLP was dismissed as the Company's independent public accountants and on March 25, 2002, Deloitte & Touche LLP was hired as the Company's independent auditors for the 2002 fiscal year. Because the former audit partner and manager have left Arthur Andersen LLP, the Company was not able to obtain the written consent of Arthur Andersen LLP as required by Section 7 of the Securities Act of 1933 (the Securities Act). Accordingly, investors will not be able to sue Arthur Andersen LLP pursuant to Section 11(a)(4) of the Securities Act and therefore may have their recovery limited as a result of the lack of consent.

NOTE 19 Subsequent Event

On January 31, 2003, Centennial Power, Inc., an indirect wholly owned subsidiary of the Company, purchased a 66.6-megawatt wind-powered electric generation facility from San Gorgonio Power Corporation, an affiliate of PG&E National Energy Group, for $102.5 million cash, subject to certain closing adjustments. This facility is located in the San Gorgonio Pass, northwest of Palm Springs, California. The facility consists of 111 wind turbines and began commercial operation in September 2001. The facility sells all of its output under a long-term contract with the California Department of Water Resources. SeaWest Wind Power, Inc. will continue to operate the facility.

To the Board of Directors and Stockholders of MDU Resources Group, Inc.:

We have audited the accompanying consolidated balance sheet of MDU Resources Group, Inc. (a Delaware corporation) and Subsidiaries as of December 31, 2002, and the related consolidated statements of income, common stockholders' equity, and cash flows for the year then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit. The consolidated financial statements of the company as of December 31, 2001, and for the years ended December 31, 2001 and 2000, were audited by other auditors who have ceased operations and whose report, dated January 23, 2002, expressed an unqualified opinion on those statements and included an explanatory paragraph that described the company's change in its method of accounting for derivative instruments due to the adoption of a new accounting pronouncement as discussed in Note 5 to the financial statements.

We conducted our audit in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the 2002 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the 2002 financial statements present fairly, in all material respects, the financial position of the company as of December 31, 2002, and the results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed above, the financial statements of the company as of December 31, 2001, and for the years ended December 31, 2001 and 2000, were audited by other auditors who have ceased operations. As described in Note 3 these financial statements have been revised to include the transitional disclosures required by Statement of Financial Accounting Standards No. 142, "Goodwill and Other Intangible Assets," (Statement) which, as described in Note 1, was adopted by the company as of January 1, 2002. Our audit procedures with respect to the disclosures in Note 3 with respect to 2001 and 2000 included (a) agreeing the previously reported net income to the previously issued financial statements and the adjustments to reported net income representing amortization expense (including any related tax effects) recognized in those periods related to goodwill that is no longer being amortized as a result of initially applying the Statement to the company's underlying records obtained from management, and (b) testing the mathematical accuracy of the reconciliation of adjusted net income to reported net income, and the related earnings per share amounts. In our opinion, the disclosures for 2001 and 2000 in Note 3 are appropriate. However, we were not engaged to audit, review, or apply any procedures to the 2001 and 2000 financial statements of the company other than with respect to such disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2001 and 2000 financial statements taken as a whole.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
January 24, 2003

THIS IS A COPY OF A REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP. THIS REPORT HAS NOT BEEN REISSUED BY ARTHUR ANDERSEN LLP NOR HAS ARTHUR ANDERSEN LLP PROVIDED A CONSENT TO THE INCLUSION OF ITS REPORT IN THIS ANNUAL REPORT. (SEE NOTE 18 OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS FOR FURTHER DISCUSSION.)

To MDU Resources Group, Inc.:

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. (a Delaware corporation) and Subsidiaries as of December 31, 2001 and 2000, and the related consolidated statements of income, common stockholders' equity and cash flows for each of the three years in the period ended December 31, 2001. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of MDU Resources Group, Inc. and Subsidiaries as of December 31, 2001 and 2000, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2001, in conformity with accounting principles generally accepted in the United States.

As explained in Note 1 to the consolidated financial statements, effective January 1, 2001, the company changed its method of accounting for derivative instruments due to the adoption of a new accounting pronouncement.

ARTHUR ANDERSEN LLP

Minneapolis, Minnesota
January 23, 2002

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2002 and 2001:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2002				
Operating revenues	$381,935	$480,218	$612,398	$556,986
Operating expenses	336,138	429,023	522,227	478,032
Operating income	45,797	51,195	90,171	78,954
Net income	23,722	24,853	53,931	45,938
Earnings per common share:				
Basic	.34	.35	.76	.63
Diluted	.34	.35	.75	.63
Weighted average common shares outstanding:				
Basic	69,469	70,456	70,923	72,095
Diluted	70,013	71,027	71,344	72,576
2001				
Operating revenues	$641,248	$546,418	$551,680	$484,286
Operating expenses	577,727	476,071	458,441	438,125
Operating income	63,521	70,347	93,239	46,161
Net income	32,687	43,417	50,746	28,999
Earnings per common share:				
Basic	.50	.64	.75	.42
Diluted	.49	.63	.74	.42
Weighted average common shares outstanding:				
Basic	65,405	67,264	67,650	68,729
Diluted	65,979	68,376	68,127	69,126

Certain Company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Natural Gas and Oil Activities (Unaudited)

Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties with potential development opportunities, exploratory drilling and the operation and development of natural gas production properties. Fidelity shares revenues and expenses from the development of specified properties located primarily in the Rocky Mountain region of the United States and in the Gulf of Mexico in proportion to its interests.

Fidelity owns in fee or holds natural gas leases for the properties it operates in Colorado, Montana, North Dakota and Wyoming. These rights are in the Bonny Field located in eastern Colorado, the Cedar Creek Anticline in southeastern Montana and southwestern North Dakota, the Bowdoin area located in north-central Montana and in the Powder River Basin of Montana and Wyoming.

The information that follows includes the Company's proportionate share of all its natural gas and oil interests held by Fidelity.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to natural gas and oil producing activities at December 31:

	2002	2001	2000
		(In thousands)	
Subject to amortization	$603,151	$506,155	$416,881
Not subject to amortization	145,692	122,354	94,856
Total capitalized costs	748,843	628,509	511,737
Less accumulated depreciation, depletion and amortization	239,964	195,469	155,198
Net capitalized costs	$508,879	$433,040	$356,539

Natural Gas and Oil Activities (Unaudited) (Continued)

Capital expenditures, including those not subject to amortization, related to natural gas and oil producing activities were as follows:

Years ended December 31,	2002	2001	2000
		(In thousands)	
Acquisitions	$ 31,439	$ 1,695	$ 68,858
Exploration	5,325	13,938	34,839
Development	94,943	102,670	69,051
Total capital expenditures	$131,707	$118,303	$172,748

The following summary reflects income resulting from the Company's operations of natural gas and oil producing activities, excluding corporate overhead and financing costs:

Years ended December 31,	2002*	2001	2000
		(In thousands)	
Revenues	$203,550	$203,727	$128,217
Production costs	55,463	47,045	33,919
Depreciation, depletion and amortization	48,064	41,223	26,739
Pretax income	100,023	115,459	67,559
Income tax expense	36,886	45,245	25,835
Results of operations for producing activities	$ 63,137	$ 70,214	$ 41,724

**Includes the compromise agreement as discussed in Note 17.*

The following table summarizes the Company's estimated quantities of proved natural gas and oil reserves at December 31, 2002, 2001 and 2000, and reconciles the changes between these dates. Estimates of economically recoverable natural gas and oil reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

	2002		2001		2000	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
			(In thousands of Mcf/barrels)			
Proved developed and undeveloped reserves:						
Balance at beginning of year	324,100	17,500	309,800	15,100	268,900	14,700
Production	(48,200)	(2,000)	(40,600)	(2,000)	(29,200)	(1,900)
Extensions and discoveries	80,100	2,200	66,400	2,000	51,300	1,600
Purchases of proved reserves	1,200	100	1,000	100	23,200	100
Sales of reserves in place	(4,400)	(300)	–	–	–	(100)
Revisions to previous estimates due to improved secondary recovery techniques and/or changed economic conditions	19,700	–	(12,500)	2,300	(4,400)	700
Balance at end of year	372,500	17,500	324,100	17,500	309,800	15,100
Proved developed reserves:						
January 1, 2000	213,400	13,300				
December 31, 2000	263,400	14,200				
December 31, 2001	291,300	17,100				
December 31, 2002	331,300	14,800				

All of the Company's interests in natural gas and oil reserves are located in the United States and in the Gulf of Mexico.

The standardized measure of the Company's estimated discounted future net cash flows of total proved reserves associated with its various natural gas and oil interests at December 31 was as follows:

	2002	2001	2000
		(In thousands)	
Future net cash flows before income taxes	$1,151,600	$548,000	$2,349,500
Future income tax expense	324,000	112,000	827,000
Future net cash flows	827,600	436,000	1,522,500
10% annual discount for estimated timing of cash flows	321,300	174,000	601,200
Discounted future net cash flows relating to proved natural gas and oil reserves	$ 506,300	$262,000	$ 921,300

The following are the sources of change in the standardized measure of discounted future net cash flows by year:

	2002	2001	2000
		(In thousands)	
Beginning of year	$ 262,000	$ 921,300	$ 229,100
Net revenues from production	(112,900)	(153,500)	(94,300)
Change in net realization	296,100	(1,119,700)	861,700
Extensions, discoveries and improved recovery, net of future production-related costs	130,600	64,200	288,700
Purchases of proved reserves	3,700	2,600	93,200
Sales of reserves in place	(8,900)	–	(1,500)
Changes in estimated future development costs, net of those incurred during the year	(100)	(3,300)	3,400
Accretion of discount	32,100	126,900	31,200
Net change in income taxes	(124,700)	436,500	(412,300)
Revisions of previous quantity estimates	30,000	(11,700)	(79,200)
Other	(1,600)	(1,300)	1,300
Net change	244,300	(659,300)	692,200
End of year	$ 506,300	$ 262,000	$ 921,300

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end natural gas prices and oil prices. Future development and production costs attributable to proved reserves were computed by applying year-end costs to be incurred in producing and further developing the proved reserves. Future income tax expenses were computed by applying statutory tax rates (adjusted for permanent differences and tax credits) to estimated net future pretax cash flows.

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of natural gas and oil prices over the remaining reserve lives may vary significantly from current prices.

	2002	2001	2000	1999	1998*	1997	1992
Selected Financial Data							
Operating revenues (000's):							
Electric	$ 162,616	$ 168,837	$ 161,621	$ 154,869	$ 147,221	$ 141,590	$ 123,908
Natural gas distribution	186,569	255,389	233,051	157,692	154,147	157,005	128,194
Utility services	458,660	364,750	169,382	99,917	64,232	22,761	–
Pipeline and energy services	165,258	531,114	636,848	383,532	180,732	87,018	92,686
Natural gas and oil production	203,595	209,831	138,316	78,394	61,842	77,916	40,088
Construction materials and mining	962,312	806,899	631,396	469,905	346,451	174,147	45,032
Independent power production	6,776	–	–	–	–	–	–
Intersegment eliminations	(114,249)	(113,188)	(96,943)	(64,500)	(57,998)	(52,763)	(67,733)
	$2,031,537	$2,223,632	$1,873,671	$1,279,809	$ 896,627	$ 607,674	$ 362,175
Operating income (000's):							
Electric	$ 33,915	$ 38,731	$ 38,743	$ 35,727	$ 32,167	$ 31,307	$ 30,188
Natural gas distribution	2,414	3,576	9,530	6,688	8,028	10,410	4,509
Utility services	13,980	25,199	16,606	11,518	5,932	1,782	–
Pipeline and energy services	39,091	30,368	28,782	40,627	33,651	25,822	18,825
Natural gas and oil production	85,555	103,943	66,510	26,845	(50,444)	27,638	12,005
Construction materials and mining	91,430	71,451	56,816	38,346	41,609	14,602	11,532
Independent power production	(268)	–	–	–	–	–	–
	$ 266,117	$ 273,268	$ 216,987	$ 159,751	$ 70,943	$ 111,561	$ 77,059
Earnings on common stock (000's):							
Electric	$ 15,780	$ 18,717	$ 17,733	$ 15,973	$ 13,908	$ 12,441	$ 13,302
Natural gas distribution	3,587	677	4,741	3,192	3,501	4,514	1,370
Utility services	6,371	12,910	8,607	6,505	3,272	947	–
Pipeline and energy services	19,097	16,406	10,494	20,972	18,651	9,955	2,270
Natural gas and oil production	53,192	63,178	38,574	16,207	(30,501)	15,867	6,960
Construction materials and mining	48,702	43,199	30,113	20,459	24,499	10,111	10,662
Independent power production	959	–	–	–	–	–	–
	$ 147,688	$ 155,087	$ 110,262	$ 83,308	$ 33,330	$ 53,835	$ 34,564
Earnings per common share – diluted	$ 2.07	$ 2.29	$ 1.80	$ 1.52	$ .66	$ 1.24	$ .81
Common Stock Statistics							
Weighted average common shares outstanding – diluted (000's)	71,242	67,869	61,390	54,870	50,837	43,478	42,741
Dividends per common share	$ .94	$ .90	$ .86	$ .82	$ .7834	$ .7534	$ .6489
Book value per common share	$ 17.34	$ 15.90	$ 13.55	$ 11.74	$ 10.39	$ 8.84	$ 7.11
Market price per common share (year-end)	$ 25.81	$ 28.15	$ 32.50	$ 20.00	$ 26.31	$ 21.08	$ 11.72
Market price ratios:							
Dividend payout	45%	39%	48%	54%	119%	61%	80%
Yield	3.7%	3.3%	2.7%	4.2%	3.0%	3.6%	5.6%
Price/earnings ratio	12.5x	12.3x	18.1x	13.2x	39.9x	17.0x	14.5x
Market value as a percent of book value	148.8%	177.0%	239.9%	170.4%	253.2%	238.5%	165.0%
Profitability Indicators							
Return on average common equity	12.5%	15.3%	14.3%	13.9%	6.5%	14.6%	11.6%
Return on average invested capital	8.6%	10.1%	9.5%	9.6%	5.5%	10.3%	8.7%
Interest coverage	7.7x	8.5x	8.3x	7.1x	6.1x	6.0x	3.3x
Fixed charges coverage, including preferred dividends	4.8x	5.3x	4.1x	4.3x	2.5x	3.4x	2.4x
General							
Total assets (000's)	$2,937,249	$2,623,071	$2,312,959	$1,766,303	$1,452,775	$1,113,892	$1,024,510
Net long-term debt (000's)	$ 819,558	$ 783,709	$ 728,166	$ 563,545	$ 413,264	$ 298,561	$ 249,845
Redeemable preferred stock (000's)	$ 1,300	$ 1,400	$ 1,500	$ 1,600	$ 1,700	$ 1,800	$ 2,300
Capitalization ratios:							
Common equity	60%	58%	54%	54%	56%	55%	53%
Preferred stocks	1	1	1	1	2	2	3
Long-term debt	39	41	45	45	42	43	44
	100%	100%	100%	100%	100%	100%	100%

**Reflects $39.9 million or 78 cents per common share in noncash after-tax write-downs of natural gas and oil properties.*
NOTE: Common stock share amounts reflect the Company's three-for-two common stock splits effected in October 1995 and July 1998.

	2002	2001	2000	1999	1998	1997	1992
Electric							
Retail sales (thousand kWh)	2,275,024	2,177,886	2,161,280	2,075,446	2,053,862	2,041,191	1,829,933
Sales for resale (thousand kWh)	784,530	898,178	930,318	943,520	586,540	361,954	352,550
Electric system generating and firm purchase capability – kW (Interconnected system)	500,570	500,820	500,420	492,800	489,100	487,500	460,200
Demand peak – kW (Interconnected system)	458,800	453,000	432,300	420,550	402,500	404,600	339,100
Electricity produced (thousand kWh)	2,316,980	2,469,573	2,331,188	2,350,769	2,103,199	1,826,770	1,774,322
Electricity purchased (thousand kWh)	857,720	792,641	948,700	860,508	730,949	769,679	593,612
Average cost of fuel and purchased power per kWh	$.018	$.018	$.016	$.016	$.017	$.018	$.016
Natural Gas Distribution							
Sales (Mdk)	39,558	36,479	36,595	30,931	32,024	34,320	26,681
Transportation (Mdk)	13,721	14,338	14,314	11,551	10,324	10,067	13,742
Weighted average degree days – % of previous year's actual	109%	95%	113%	95%	94%	85%	98%
Pipeline and Energy Services							
Sales for resale (Mdk)	–	–	–	–	–	–	16,841
Transportation (Mdk)	99,890	97,199	86,787	78,061	88,974	85,464	64,498
Gathering (Mdk)	72,692	61,136	41,717	19,799	9,093	9,550	6,735
Natural Gas and Oil Production							
Production:							
Natural gas (MMcf)	48,239	40,591	29,222	24,652	20,699	20,407	8,805
Oil (000's of barrels)	1,968	2,042	1,882	1,758	1,912	2,088	1,531
Average realized prices:							
Natural gas (per Mcf)	$ 2.72	$ 3.78	$ 2.90	$ 1.94	$ 1.81	$ 2.02	$ 1.58
Oil (per barrel)	$22.80	$24.59	$23.06	$15.34	$12.71	$17.50	$16.74
Net recoverable reserves:							
Natural gas (MMcf)	372,500	324,100	309,800	268,900	243,600	184,900	37,200
Oil (000's of barrels)	17,500	17,500	15,100	14,700	11,500	14,900	12,200
Construction Materials and Mining							
Construction materials (000's):							
Aggregates (tons sold)	35,078	27,565	18,315	13,981	11,054	5,113	263
Asphalt (tons sold)	7,272	6,228	3,310	2,993	1,790	758	–
Ready-mixed concrete (cubic yards sold)	2,902	2,542	1,696	1,186	1,021	516	–
Recoverable aggregate reserves (tons)	1,110,020	1,065,330	894,500	740,030	654,670	169,375	20,600
Coal (000's):							
Sales (tons)	–*	1,171*	3,111	3,236	3,113	2,375	4,913
Recoverable reserves (tons)	37,761*	56,012*	145,643	182,761	190,152	226,560	235,700
Independent Power Production**							
Net generation capacity – kW	213,000	–	–	–	–	–	–
Electricity produced and sold (thousand kWh)	15,804	–	–	–	–	–	–

** Coal operations were sold effective April 30, 2001.*
*** Reflects domestic independent power production operations acquired in November 2002.*

Numbers indicate age and years of service ( ) on the MDU Resources Group, Inc. Board of Directors as of December 31, 2002.

Board Change
Douglas C. Kane, former executive vice president, chief administrative and corporate development officer of MDU Resources Group, Inc. accepted a new position with the company in October 2002 and resigned as a director at that time.

Audit Committee
Homer A. Scott, Jr., Chairman
Bruce R. Albertson
Dennis W. Johnson
John L. Olson
Harry J. Pearce

Compensation Committee
Harry J. Pearce, Chairman
Thomas Everist
Homer A. Scott, Jr.

Finance Committee
Dr. Joseph T. Simmons, Chairman
Thomas Everist
Dennis W. Johnson
Robert L. Nance
Sister Thomas Welder, O.S.B.

Nominating Committee
John L. Olson, Chairman
Bruce R. Albertson
Robert L. Nance
Dr. Joseph T. Simmons
Sister Thomas Welder, O.S.B.

Martin A. White, 61 (5)
Mandan, North Dakota

Chairman of MDU Resources Group, Inc. Board of Directors

President and Chief Executive Officer of MDU Resources Group, Inc.

Harry J. Pearce, 60 (6)
Detroit, Michigan

Lead Director of MDU Resources Group, Inc. Board of Directors

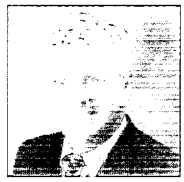
Chairman of Hughes Electronics Corporation, a unit of General Motors Corporation, former vice chairman and director of General Motors; also serves as a director of numerous major corporations

Expertise: Multi-national business management, engineering and law

Bruce R. Albertson, 57 (2)
Pompano Beach, Florida

President and Chief Executive Officer, Brown Jordan International, formerly president and chief executive officer of Iomega Corporation and vice president, marketing and product management worldwide of General Electric Company

Expertise: Technology, marketing and international business



Thomas Everist, 53 (7)
Sioux Falls, South Dakota

President and chairman of The Everist Company, an aggregate, concrete and asphalt production company; also serves as a director of an engineering and architectural consulting firm

Expertise: Business management, construction and sand, gravel and aggregate production

Dennis W. Johnson, 53 (2)
Dickinson, North Dakota

Chairman and chief executive officer of TMI Systems Design Corporation, a manufacturer of custom institutional furniture; previously served as a director of Federal Reserve Bank of Minneapolis

Expertise: Business management, engineering and finance

Robert L. Nance, 66 (10)
Billings, Montana

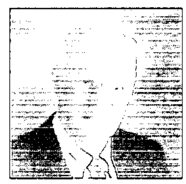
President and chief executive officer of Nance Petroleum Corporation, a wholly owned subsidiary of St. Mary Land & Exploration Co., an oil and natural gas exploration company of which he also is a director and senior vice president; a member of the board of a petroleum industry organization

Expertise: Oil and natural gas industry, petroleum geology and technology

John L. Olson, 63 (18)
Sidney, Montana

President and chief executive officer of Blue Rock Products Company and Blue Rock Distributing Company, beverage bottling and distribution companies with operations and franchises in the western United States

Expertise: Marketing and western U.S. business development and franchising



Homer A. Scott, Jr., 68 (22)
Sheridan, Wyoming

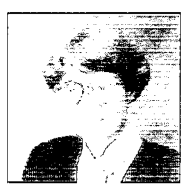
Chairman of the board of First Interstate BancSystem, Inc., and managing partner of a commercial property development company

Expertise: Construction industry and banking

Dr. Joseph T. Simmons, 67 (19)
Rapid City, South Dakota

Retired; former professor of accounting and finance at the University of South Dakota as well as financial management company owner

Expertise: Finance and accounting



Sister Thomas Welder, O.S.B., 62 (15)
Bismarck, North Dakota

President of University of Mary; also a member of the North Dakota Supreme Court's Public Trust and Confidence Implementation Committee

Expertise: Business development and management

Expanded biographies of all board members can be found in the 2003 MDU Resources Group, Inc. Proxy Statement.

Corporate Management

Numbers indicate age and years of service ( ) as of December 31, 2002.

Corporate Officers

Martin A. White
Chairman of the Board
President and
Chief Executive Officer, 61 (11)

Cathleen M. Christopherson
Vice President – Corporate Communications, 58 (35)

Richard A. Espeland
Vice President – Human Resources, 59 (13)

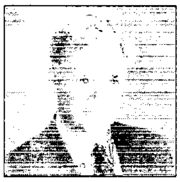
Lester H. Loble, II
Executive Vice President, General Counsel and Secretary, 61 (15)

Vernon A. Raile
Senior Vice President, Controller and Chief Accounting Officer, 57 (22)

Warren L. Robinson
Executive Vice President, Treasurer and Chief Financial Officer, 52 (14)

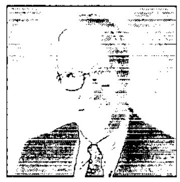
Robert E. Wood
Vice President – Public Affairs and Environmental Policy, 60 (28)

Management Policy Committee



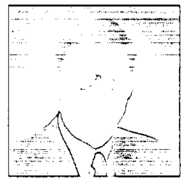
Martin A. White
Chairman of the Board, President and Chief Executive Officer, MDU Resources Group, Inc., 61 (11)

Serves on the company Board of Directors and as chairman of the board of major subsidiary companies. Previously senior vice president – corporate development of the company; also held executive and management positions with an independent international energy consulting firm, a South American mining corporation and a Montana-based natural resources and utility corporation.



John K. Castleberry
President and Chief Executive Officer, WBI Holdings, Inc., 48 (20)

Serves as chief executive officer and/or president of all subsidiaries of WBI Holdings. Previously held various executive and management positions with Williston Basin Interstate Pipeline Company and Montana-Dakota Utilities Co.



Richard A. Espeland
Vice President – Human Resources, MDU Resources Group, Inc., 59 (13)

Serves as human resource leader for the corporation. Previously held human resource management and executive positions with another energy company and state and local government.

Terry D. Hildestad
President and Chief Executive Officer, Knife River Corporation, 53 (28)

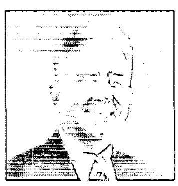
Serves as chief executive officer of all construction materials and mining subsidiaries of Knife River Corporation. Previously held management and executive positions in operations with Knife River.

Lester H. Loble, II
Executive Vice President, General Counsel and Secretary, MDU Resources Group, Inc., 61 (15)

Serves as general counsel and secretary for all major company subsidiaries. Engaged in the private practice of law prior to joining the company.

Warren L. Robinson
Executive Vice President, Treasurer and Chief Financial Officer, MDU Resources Group, Inc., 52 (14)

Serves as the senior financial officer and member of the board of directors of all major subsidiary companies. Previously held executive and management positions in finance, corporate planning and development with the company, as well as with several natural gas utility companies in the western United States.



Ronald D. Tipton
Chief Executive Officer, Montana-Dakota Utilities Co., Great Plains Natural Gas Co. and Utility Services, Inc., 56 (19)

Serves as chief executive officer of all utility services subsidiaries. Previously served as president of Montana-Dakota Utilities Co., Great Plains Natural Gas Co. and Utility Services, Inc. He also served as president and chief executive officer of Williston Basin Interstate Pipeline Company and in various executive and management positions in their operations. Also served in executive and management positions with two other energy and natural gas corporations.

Corporate Accountability: It's part of our culture

MDU Resources takes pride in its corporate accountability. The company has long practiced many of the requirements that are now part of the Sarbanes-Oxley Act of 2002 that was enacted in July 2002. The company also meets or exceeds many of the proposals that the New York Stock Exchange Board of Directors ratified in August.

Practices in place prior to 2002

- Nonemployee directors comprise a majority of the board and one serves as lead director.
- All committees are comprised solely of nonemployee directors.
- There are no interlocks among Compensation Committee members.
- Company has an internal audit function.
- Code of business conduct and ethics has been adopted, and to date there have been no waivers of the code for directors or executive officers.
- Shareholders have been given the opportunity to vote on stock-option plans.
- Nonemployee directors meet without management in regular executive sessions.
- Each incumbent director attended more than 90 percent of the combined total meetings of the board and the committees on which the director served in 2002 and more than 75 percent of the meetings in 2001.
- Directors receive all or a portion of their compensation in the form of equity. Each director who has served on the board for more than two years owns an equity interest in the company totaling at least $150,000 (excluding Sister Thomas Welder).
- Nonemployee directors do not participate in the company's pension plan.
- Audit Committee regularly reviews interim quarterly and annual financials and the related independent auditors' report.
- Audit Committee meets separately with management, independent auditors and internal auditors on a quarterly basis.

Adopted in 2002

- Chief executive officer and the chief financial officer began certifying certain Securities and Exchange Commission filings made by the company.

Vernon A. Raile, senior vice president, controller and chief accounting officer (C), received the company's first ever MDU Resources' Integrity Award. Janelle Steiner, financial analyst, and Dan Moylan, corporate accounting manager, are part of the team that analyzes MDU Resources financial information.
▽

We're proud that most of the changes now being required by law have been practiced at our company for years.

- Updated and implemented disclosure controls and procedures designed to assure accurate and timely Exchange Act reporting and to support chief executive officer and chief financial officer quarterly and annual certifications.
- Disclosure Policy Committee, which includes several members of senior corporate management, has responsibility for managing disclosure to the financial community and addressing compliance with SEC Regulation Fair Disclosure.

Practices we plan to adopt in 2003

- Corporate governance guidelines and charters of the Audit, Compensation and Nominating Committees will be placed on the company Web site at www.mdu.com.*
- Code of ethics for directors, officers and employees will be included on the company Web site.*
- SEC Forms 4 and 5, which report sales or purchases of company stock by officers and directors, will be posted on the company Web site.

Employee programs

The company has initiated the following programs to help make employees aware of their responsibility on corporate accountability issues:

- Learn the Law Program: Makes employees aware of various laws that apply to their organization and encourages them to report any questionable practices or violations of law to their supervisor or other company personnel, including senior management and the Board of Directors.
- Code of Conduct: Since the early 1980s, all employees in management positions at all operating companies and the corporate office annually sign a code of conduct.
- U. S. Federal Sentencing Guidelines Policy: In place since 1994 to establish an effective program to assure compliance with applicable laws.
- It's a Matter of Ethics: In effect since 1987 to provide employees guidance on several areas of ethical behavior.
- Training on Specific Federal Laws: Employees who work with international operations are provided guidance on compliance with applicable laws.

** These items also will be available in print to any stockholder who requests a copy.*

Corporate Headquarters
MDU Resources Group, Inc.
Schuchart Building
Street Address: 918 East Divide Avenue
Mailing Address: P.O. Box 5650
Bismarck, ND 58506-5650
Telephone (toll-free): (800) 437-8000

Market Information
The company's common stock is listed on the New York Stock Exchange and the Pacific Stock Exchange under the symbol MDU. The stock began trading on the NYSE in 1948 and is included in the Standard & Poor's MidCap 400 index. Average daily trading volume in 2002 was 186,953 shares. The range of high, low and closing quarterly common stock sales prices for 2002 and 2001, as reported by the NYSE are listed below:

	High	Low	Close
2002			
First Quarter	$31.09	$27.25	$31.00
Second Quarter	33.45	25.75	26.29
Third Quarter	27.40	18.00	22.83
Fourth Quarter	25.99	20.91	25.81
2001			
First Quarter	$35.76	$27.38	$35.72
Second Quarter	40.37	31.38	31.64
Third Quarter	32.90	22.38	23.37
Fourth Quarter	28.30	23.00	28.15

Dividend Reinvestment and Stock Purchase Plan
MDU Resources Group, Inc. Automatic Dividend Reinvestment and Stock Purchase Plan allows any individual who is a legal resident of the nation's 50 states to buy MDU Resources common stock direct from the company without incurring any brokerage fees. For further details, including enrollment information, contact the stock transfer agent or the Investor Relations Department at MDU Resources.

2003 Key Dividend Dates*

	Ex-Dividend Date	Record Date	Payment Date
1st Quarter	March 11	March 13	April 1
2nd Quarter	June 10	June 12	July 1
3rd Quarter	September 9	September 11	October 1
4th Quarter	December 9	December 11	January 1, 2004

**Subject to discretion of the Board of Directors*

Internet Account Access
Registered shareholders have electronic access to their shareholder accounts by visiting www.shareowneronline.com. Shareholders can view their account balance, certificate information and account registration, as well as request reissuance of uncashed dividend checks. Wells Fargo Bank Minnesota, N.A., the transfer agent and registrar, maintains shareholder account access.

Stockholder Services
Stockholders or others desiring information about MDU Resources should call *Arlene Stillwell* in the Investor Relations Department at *(800) 437-8000, extension 7621,* or e-mail *investor@mduresources.com.* Information on the company also may be found on the Web site at www.mdu.com.

Communications regarding stock transfer requirements, lost certificates, dividends or change of address should be directed to the stock transfer agent.

Brokerage Accounts
Stock purchased and held for stockholders by brokers is listed in the broker's name, or "street name." Annual and quarterly reports, proxy material and dividend payments are sent to stockholders by their broker. Questions regarding mailings or dividend reinvestment should be directed to the broker.

Annual Meeting
The Annual Meeting of Stockholders is scheduled for 11 a.m. Central Daylight Time, Tuesday, April 22, 2003, at the Montana-Dakota Utilities Co. Service Center, 909 Airport Road, Bismarck, ND.

Transfer Agent and Registrar for all Classes of Stock and Dividend Reinvestment Plan Agent
Wells Fargo Bank Minnesota, N.A.
Stock Transfer Department
P.O. Box 64854
St. Paul, MN 55164-0854
Telephone: (651) 450-4064
Telephone (toll-free): (877) 536-3553
www.wellsfargo.com/shareownerservices

Transfer Agent and Registrar for First Mortgage Bonds
The Bank of New York
Corporate Trust Department
101 Barclay Street, 21st Floor
New York, NY 10286

Independent Auditors
Deloitte & Touche LLP
400 One Financial Plaza
120 S. Sixth St.
Minneapolis, MN 55402-1844

Form 10-K Information
The company's Annual Report on Form 10-K (excluding exhibits) for the year ended Dec. 31, 2002, as filed with the Securities and Exchange Commission, is available to stockholders without charge. A copy may be requested from the Investor Relations Department at MDU Resources. All reports filed with the SEC also are available through the investor section of our Web site.

NOTE: This information is not given in connection with any sale or offer for sale or offer to buy any security.

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Printed on recycled paper

Terminology

Aggregates: Sand, gravel or rock used primarily for construction purposes.

Book value per common share: Common stockholders' equity divided by the number of shares of common stock outstanding.

Construction materials: Asphalt, cement, concrete reinforcement steel, concrete masonry block, ready-mixed concrete and aggregates.

Distribution: The delivery of electricity or natural gas to homes, businesses and other end users.

Dividend payout ratio: The percentage of earnings paid out to common stockholders in dividends; calculated by dividing dividends by earnings.

Electric sales for resale: Electric energy sales to customers who, in turn, resell it to their customers. Typically these sales are accomplished between electric utility companies.

Environmental Protection Agency (EPA): Federal agency that works with other federal agencies, state and local governments, and Indian tribes to develop and enforce regulations under existing environmental laws. The agency also works with industries and all levels of government in a wide variety of voluntary pollution prevention programs and energy conservation efforts.

Federal Energy Regulatory Commission (FERC): Federal agency within the Department of Energy regulating prices and conditions of service for interstate electricity and natural gas transmission and sale.

Fixed charges coverage ratio: A measure of a company's ability to meet its fixed-charge obligations. To calculate, divide earnings before taxes plus interest plus certain rent expense by interest plus certain rent expense.

Hedging: The process of reducing financial exposure by entering into offsetting transactions.

Infrastructure: A substructure or underlying foundation, especially the basic installations and facilities on which the continuance and growth of a community depends, such as roads, power plants, transportation and communication systems.

Interest coverage ratio: A measure of a company's ability to meet its interest payments. To calculate, divide net earnings plus interest expense by interest expense.

Natural gas storage: Natural gas usually is stored in a depleted oil or natural gas field. Natural gas is injected and withdrawn as needed primarily to help meet winter heating demand.

Nonemployee director: A member of the Board of Directors who is not employed by the company or any of its subsidiaries.

Price/earnings ratio: The price of a share of common stock divided by earnings per common share for a 12-month period.

Reserves: Estimated volumes of natural gas, oil, coal or aggregates in the ground that can be economically recovered with reasonable certainty.

Retained earnings: The earnings that a corporation does not pay out in dividends.

Return on average common equity: Earnings on common stock divided by average common stockholders' equity for a 12-month period.

Return on average invested capital: Net income before interest net of tax, divided by average capitalization for a 12-month period.

Securities and Exchange Commission (SEC): Federal agency that regulates financial markets. It also requires public companies to disclose certain meaningful financial and other information to the public.

Transmission: The movement of electricity or natural gas from its source to a local distribution system.

Throughput: Volume of natural gas moved through a pipeline to end users.

Units of Measure

Bcf: Billion cubic feet.

Bcfe: Billion cubic feet equivalent; standard conversion of barrels of oil to natural gas equivalent volume; 1 million barrels of oil equates to 6 billion cubic feet of natural gas equivalent.

Btu: British thermal unit; a standard unit for measuring heat, 1 Btu represents the quantity of heat necessary to raise the temperature of 1 pound of water 1 degree Fahrenheit.

dk: Decatherm; measures heating value, 1 decatherm of natural gas has the energy equivalent of 1 million Btu.

kW: Kilowatt; a measure of electric power equal to 1,000 watts.

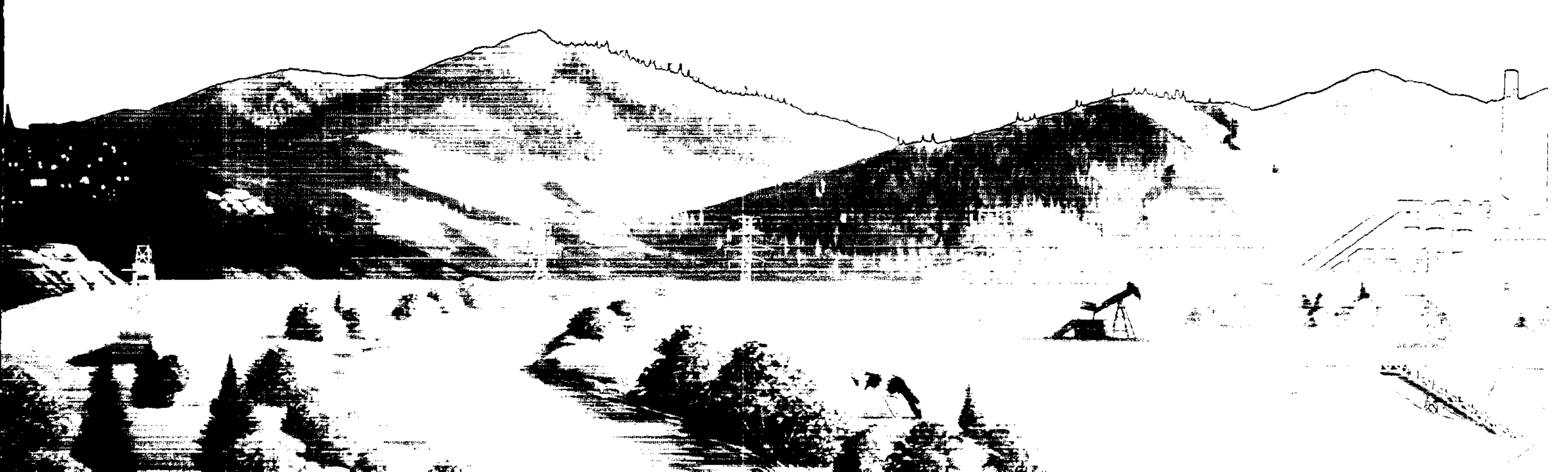
kWh: Kilowatt-hour; a measure of electricity consumption equivalent to the use of 1,000 watts of power over a period of one hour.

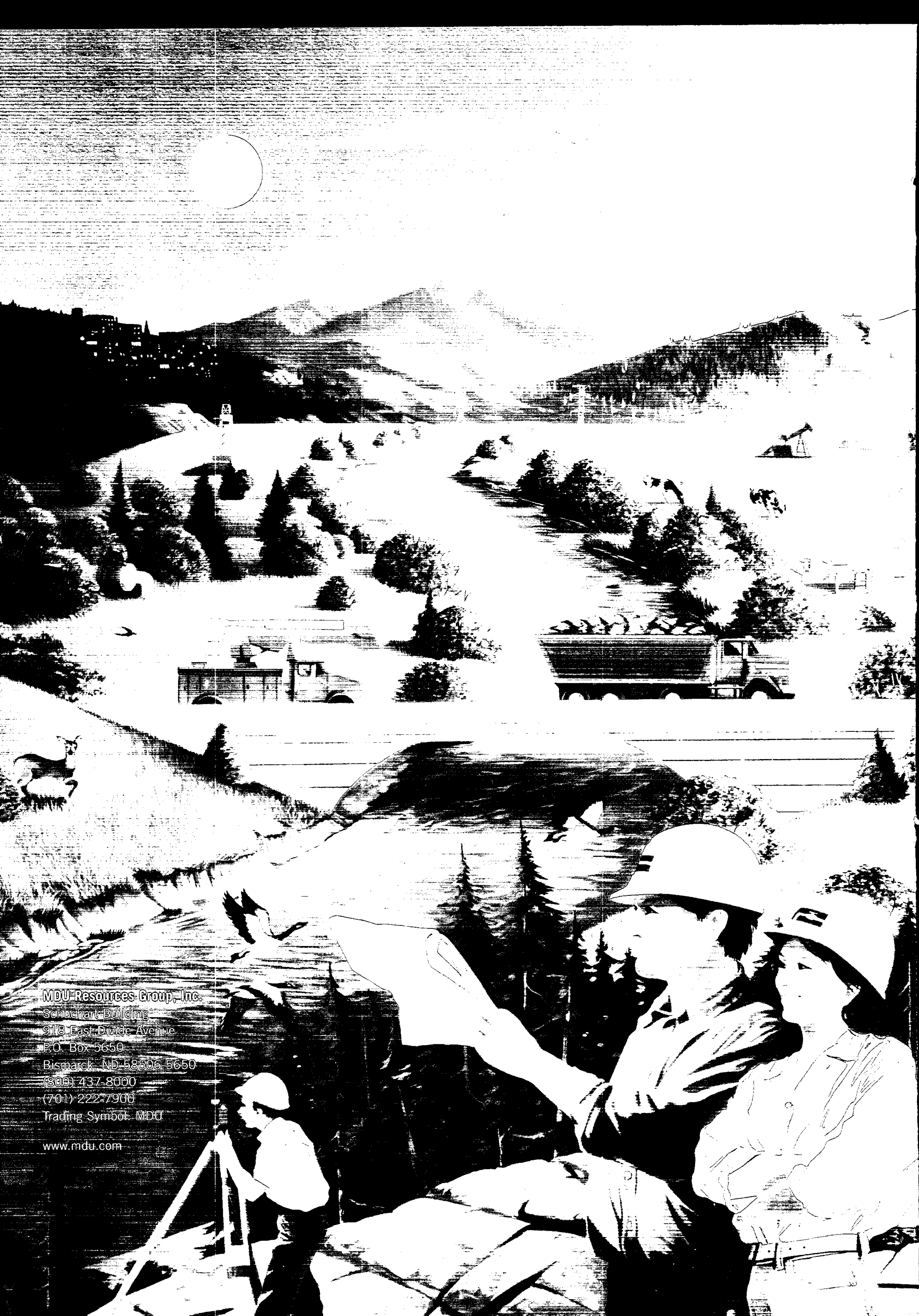
Mcf: Thousand cubic feet; a standard volume measure for natural gas.

MMcf: Million cubic feet.

MMdk: Million decatherms.

MW: Megawatt; a measure of electric power equal to 1 million watts.





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