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Building a Strong America

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MDU RESOURCES GROUP, INC.

COMPANY DESCRIPTION

MDU Resources Group, Inc., a member of the S&P MidCap 400 index, provides value-added natural resource products and related services that are essential to our country's energy and transportation infrastructure. MDU Resources includes electric and natural gas utilities, natural gas pipelines and energy services, utility services, natural gas and oil production, construction materials and mining, and domestic and international independent power production.

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.

OUR GUIDING PRINCIPLES

To achieve our 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.

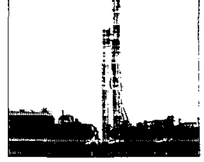
Ethics Conduct business with integrity and with respect for all.

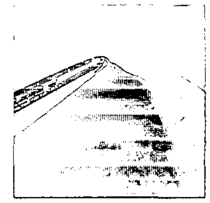
Employees Develop individual potential and teamwork to maintain employees as our ongoing source of competitive advantage.

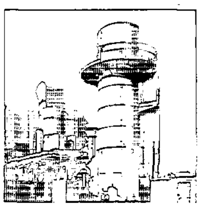
Safety Perform all tasks with health and safety first.

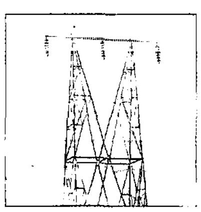
On the cover
The front cover depicts our lines of business and describes how our people, products and services contribute to **Building a Strong America**. Operating companies are listed on the back cover.

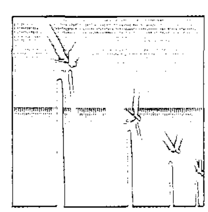
Forward-looking statements
This Annual Report contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in Management's Discussion and Analysis – Risk Factors and Cautionary Statements that May Affect Future Results, as well as other factors that are listed in Part I of the company's 2003 Form 10-K. 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.












Alaska
Hawaii
Brazil
Electric
Natural Gas Distribution
Utility Services Offices
Utility Services Authorized States of Operations
Pipeline and Energy Services
Natural Gas and Oil Production
Construction Materials and Mining
Independent Power Production and Other

ELECTRIC AND NATURAL GAS DISTRIBUTION

Revenues (millions)	
Electric	$178.6
Natural gas distribution	$274.6
Earnings (millions)	
Electric	$16.9
Natural gas distribution	$3.9
Electric sales (million kWh)	
Retail	2,359.9
Sales for resale	841.6
Natural gas distribution (MMdk)	
Sales	38.6
Transportation	13.9
Corporate earnings contribution	
Electric	10%
Natural gas distribution	2%

- **Electric customers:**

Residential	97,011
Commercial	18,126
Industrial and other	2,001

- **Natural gas customers:**

Residential	215,742
Commercial	27,878
Industrial	104

- **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

UTILITY SERVICES

Revenues (millions)	$434.2
Earnings (millions)	$6.2
Corporate earnings contribution	4%

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

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

PIPELINE AND ENERGY SERVICES

Revenues (millions)	$252.2
Earnings (millions)	$18.2
Pipeline (MMdk)	
Transportation	90.2
Gathering	75.9
Corporate earnings contribution	10%

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

Other natural gas pipeline and gathering companies such as Kinder-Morgan, Inc.; Northern Border Pipeline Co.; Questar Pipeline; Colorado Interstate Gas Co.; Bear Paw Energy, LLC and Thunder Creek Gas Gathering

NATURAL GAS AND OIL PRODUCTION

Revenues (millions)	$264.3
Earnings (millions)	$63.0*
Production	
Natural gas (Bcf)	54.7
Oil (million barrels)	1.9
Net recoverable reserves	
Natural gas (Bcf)	411.7
Oil (million barrels)	18.9
Corporate earnings contribution	36%

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

Independent natural gas and oil companies such as XTO, Tom Brown Inc., St. Mary Land & Exploration Co., and Patina Oil & Gas Corp.

CONSTRUCTION MATERIALS AND MINING

Revenues (millions)	$1,104.4
Earnings (millions)	$54.4*
Sales (millions)	
Aggregates (tons)	38.4
Asphalt (tons)	7.3
Ready-mixed concrete (cubic yards)	3.5
Recoverable aggregate reserves (billion tons)	1.2
Corporate earnings contribution	31%

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

Other construction materials companies such as LaFarge Corp., Vulcan Materials Co., Martin Marietta Materials, Rinker Materials Corp., Oldcastle Inc. and Teichert, Inc.

INDEPENDENT POWER PRODUCTION AND OTHER**

Revenues (millions)	$35.0
Earnings (millions)	$12.0
Electricity produced and sold*** (million kWh)	270.0
Corporate earnings contribution	7%

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

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

** Includes cumulative effect of the change in accounting for asset retirement obligations required by the adoption of SFAS No. 143, as discussed in Notes 1 and 9.*

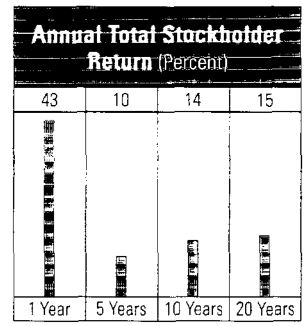
*** Reflects domestic and international independent power production operations. The earnings from the company's equity method investment in Brazil were included in other income – net.*

**** Reflects domestic independent power production operations.*

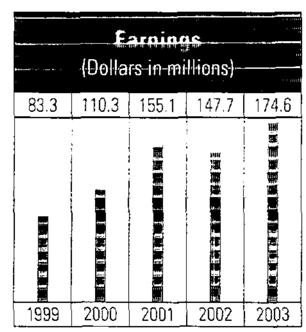
Years ended December 31,	2003	2002	Increase/Decrease Amount	Percent
		(In millions, where applicable)		
Operating revenues:				
Electric	**$ 178.6**	$ 162.6	$ 16.0	10
Natural gas distribution	**274.6**	186.6	88.0	47
Utility services	**434.2**	458.7	(24.5)	(5)
Pipeline and energy services	**252.2**	165.2	87.0	53
Natural gas and oil production	**264.3**	203.6	60.7	30
Construction materials and mining	**1,104.4**	962.3	142.1	15
Independent power production and other	**35.0**	6.8	28.2	–
Intersegment eliminations	**(191.1)**	(114.3)	(76.8)	(67)
Total	**$2,352.2**	$2,031.5	$320.7	16
Operating income:				
Electric	**$ 35.8**	$ 33.9	$ 1.9	5
Natural gas distribution	**6.5**	2.4	4.1	169
Utility services	**12.9**	14.0	(1.1)	(8)
Pipeline and energy services	**35.2**	39.1	(3.9)	(10)
Natural gas and oil production	**118.3**	85.6	32.7	38
Construction materials and mining	**91.6**	91.4	.2	–
Independent power production and other	**11.8**	(.3)	12.1	–
Total	**$ 312.1**	$ 266.1	$ 46.0	17
Earnings on common stock:				
Electric	**$ 16.9**	$ 15.8	$ 1.1	7
Natural gas distribution	**3.9**	3.6	.3	8
Utility services	**6.2**	6.4	(.2)	(3)
Pipeline and energy services	**18.2**	19.1	(.9)	(5)
Natural gas and oil production	**70.7***	53.2	17.5	33
Construction materials and mining	**54.3***	48.7	5.6	11
Independent power production and other	**12.0**	.9	11.1	–
	182.2*	147.7	34.5	23
Cumulative effect of accounting change	**(7.6)**	–	(7.6)	–
Total	**$ 174.6**	$ 147.7	$ 26.9	18
Earnings per common share – basic:				
Earnings before cumulative effect of accounting change	**$ 1.64***	$ 1.39	$ .25	18
Cumulative effect of accounting change	**(.07)**	–	(.07)	–
Earnings per common share – basic	**$ 1.57**	$ 1.39	$ .18	13
Earnings per common share – diluted:				
Earnings before cumulative effect of accounting change	**$ 1.62***	$ 1.38	$ .24	17
Cumulative effect of accounting change	**(.07)**	–	(.07)	–
Earnings per common share – diluted	**$ 1.55**	$ 1.38	$ .17	12
Dividends per common share	**$ .6600**	$ .6266	$.0334	5
Weighted average common shares outstanding – diluted	**112.5**	106.9	5.6	5
Total assets	**$3,380.6**	$2,996.9	$383.7	13
Total equity	**$1,450.6**	$1,298.7	$151.9	12
Net long-term debt	**$ 939.5**	$ 819.6	$119.9	15
Capitalization ratios:				
Common equity	**60%**	60%		
Preferred stocks	**1**	1		
Long-term debt	**39**	39		
	100%	100%		
Return on average common equity	**13.0%**	12.5%		
Price/earnings ratio	**15.4x**	12.5x		
Book value per common share	**$ 12.66**	$ 11.56		
Market value as a percent of book value	**188.1%**	148.8%		
Full-time employees	**7,797**	6,983		

** Before cumulative effect of the change in accounting for asset retirement obligations required by the adoption of Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."*

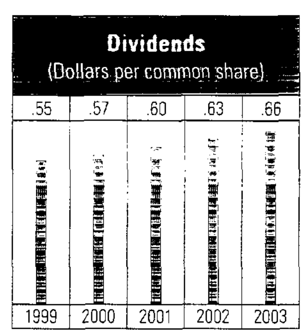
NOTE: Common stock share amounts reflect the company's three-for-two common stock split effected in October 2003.



Stock price appreciation and increasing dividends benefit stockholders.



Earnings reflect the company's successful growth strategy.



Dividends have increased 20 percent since 1999.

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

Building a strong America for 80 years

On March 14, 2004, MDU Resources will celebrate its 80th anniversary. For eight decades we've been providing the essential products and services that support this country's infrastructure.

We produce energy – natural gas, oil and electricity. We mine aggregates and use aggregate-based construction materials to build roads and bridges. We distribute the electricity and natural gas we produce. We build electric and natural gas distribution and transmission lines. We wire commercial buildings and install and maintain street and traffic light systems. If you eliminated these fundamental services, America's economy would come to a halt.

That's one of the reasons we're enthusiastic about MDU Resources' future. While the economy struggled, we thrived. The services we provide aren't glamorous, but they are indeed the strong foundation that supports our American way of life.

Solid performance

We are extremely pleased with our 2003 results. We had record earnings of $174.6 million for 2003, compared to $147.7 million for 2002. Earnings per common share, diluted, totaled $1.55, compared to $1.38 for 2002.

Once again, we have outperformed our peer groups by a wide margin. Our one-year total shareholder return is 43 percent, compared to 35 percent for our peers and 29 percent for the S&P 500. And if you look at the past three years, which were tough for many companies, our total annual return was 7 percent, while our peer average was 2 percent and the S&P 500 returned a negative 4 percent.

In August, we increased our dividend 6.3 percent, the 13th consecutive year of increased dividends. MDU Resources has an unbroken record of quarterly dividend payments since 1937. In addition, our stock was split on a three-for-two basis, effective Oct. 29, 2003. We think that sends a strong signal that we expect the company to continue to do well in the future.

In January 2004, Forbes magazine named MDU Resources the best managed big company in the utilities category from its list of America's 400 Best Big Companies. Forbes selects companies across 26 core industries and ranks them against their peers for five-year total returns, long- and short-term sales and earnings growth and other yardsticks such as long-term earnings forecasts. Additional factors considered were market leadership, innovation and efficiency.

According to the Fortune 1000 list published in the April 14, 2003, issue of Fortune Magazine, MDU Resources ranked 666 based on total revenues, but No. 1 in the energy industry in total return to investors for 1992–2002 with an annual return of 13 percent. The company also ranked No. 1 in the industry for earnings per share annual growth with a 10 percent annual growth rate for the years 1992–2002.

While these honors are exciting, what's most important is that our strategies, built on our vision statement, are proving themselves through challenging economic times as well as through growth periods.

Trends support strategies

In 2001, the American Society of Civil Engineers released a report card on our nation's infrastructure. They gave it a D+. Recently, ASCE issued a progress report that said the country has failed to even maintain the substandard conditions of its roads and bridges from two years ago. Experts say capital outlays would have to increase by 42 percent to reach a maintenance level and by 94 percent to improve roads and bridges. The Federal Highway Administration says that traffic congestion costs the economy $67.5 billion annually in lost productivity and wasted fuel.

ASCE also reports that the condition of our nation's energy infrastructure has deteriorated. Over the past two decades, investment in electric transmission infrastructure has decreased by $115 million per year. ASCE predicts that it will take an investment of $1.6 trillion over a five-year period for transportation, energy and other infrastructure renewal. The Aug. 14, 2003, blackout in the eastern United States and Canada has increased the public's awareness of this issue.

In addition, the National Petroleum Council predicts that the demand for natural gas will increase from today's nearly 23 trillion cubic feet per day to nearly 30 Tcf by 2025. It estimates $3 billion per year – or $70 billion by 2025 – will be spent on natural gas distribution facilities and for expansion of interstate pipelines and underground storage.

We are involved in businesses that help fill the essential infrastructure needs noted in these reports. That's why we feel our strategies are sound.

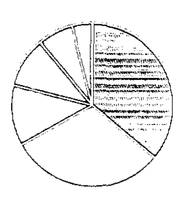
Operating highlights

Our natural gas and oil business had an excellent year. Natural gas prices were 43 percent higher this year, while oil prices were 20 percent higher. We increased our natural gas and oil production and reserves 10 percent in 2003. Over the years, we've changed our business philosophy. We shifted our emphasis to focus primarily on properties we own and operate ourselves, rather than relying on production from properties operated by others. We've been in the natural gas and oil business since the 1920s, and we are still producing from some of our original fields. Our recent success speaks to the expertise and innovation of our employees in implementing new technologies that enhance production from existing properties. This expertise also will serve us well as we seek new production areas to replenish and continually expand our reserve base.

Our construction materials and mining company had an outstanding year, exceeding $1 billion in revenue for the first time. The first part of our vision statement says that we will "with integrity, create superior shareholder value by expanding upon our expertise." This business illustrates the concrete results of living that vision. We used our coal mining expertise and applied it to mining aggregates and launched our construction materials business. We started growing this business in 1992 when the entire corporation's revenues were about $360 million. Now the corporation's revenues are $2.4 billion, and construction materials and mining revenues this year accounted for about half of that amount.

Just as in our natural gas and oil business, we believe in acquiring strategically positioned reserves. Owning reserves in areas where they are or will be needed in the future helps make us the supplier of choice – another key part of our vision statement. We now have about 1.2 billion tons of aggregate reserves and operations in 10 states. This year we acquired a large construction materials company in Texas. That state spends an average of $3.3 billion annually, with every expectation that the Texas highway program will remain robust. We are now strategically positioned to serve

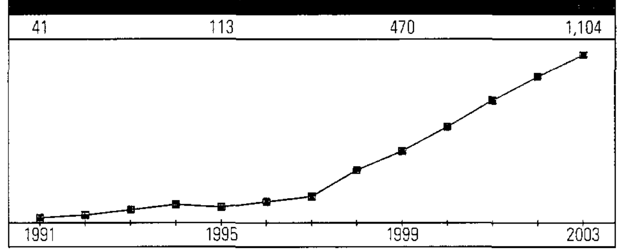
2003 Earnings by Business
(Dollars in millions)



$63.0	36%	Natural gas and oil production
54.4	31	Construction materials and mining
20.8	12	Electric and natural gas distribution
18.2	10	Pipeline and energy services
12.0	7	Independent power production & other
6.2	4	Utility services

Each of the company's businesses contributes to its overall success.

Construction Materials and Mining Revenues
(Dollars in millions)



Construction materials and mining revenues totaled over $1 billion in 2003, nearly equaling MDU Resources' total revenues in 1999.

that market. Our construction materials companies also have a significant presence in Oregon that will allow them to take advantage of the $1.6 billion in bridge improvements that state recently approved. This is part of a $2.5 billion transportation funding package, the largest infrastructure investment in Oregon since World War II.

Our utilities have been consistent performers throughout our history, and we have every reason to believe that will continue. We added a new 40-megawatt, natural gas-fired peaking unit in Montana this year and are considering building new generation for the utility. These plants will help ensure our customers receive reliable, reasonably priced energy for years to come.

The completion of the Grasslands Pipeline was the major achievement of our pipeline and energy services business this year. This 253-mile pipeline was the largest pipeline construction project ever undertaken by the company. It will enable us to move the natural gas that we produce to access broader markets. Current pipeline capacity is 90 million cubic feet per day with possible expansion up to 200 MMcf per day.

Due to the weakness in the economy, it was a tough year for businesses in the utility services industry; however, our company only had a slight decrease in earnings as a result of sound management and aggressive marketing of its diverse services. Electric linebuilding increases in California, higher demand for line tensioning equipment and new contracts to wire industrial facilities indicate that this business is improving.

We're very pleased with the contribution of our independent power production business this year. Our domestic operations added wind generation, and our Brazilian operations performed very well. We expect to see even more growth in this business in the next five years. As with other new businesses we ventured into as expansions of our expertise, our approach to our Brazilian operation has been cautious and disciplined. We started with a project in which we had expertise and worked with our Brazilian Advisory Board to help ensure success. We have increased our international business acumen while making money for our shareholders. It's a good investment in our future. As the world becomes smaller, it's more important than ever to have international expertise.

Total stockholder return 43 percent

Employees critical to success

I am very proud of our employees, who are the foundation of our success. Their expertise allows us to respond promptly to opportunities that present themselves. I like to think of all of us working together to build this great company as if we were building a foundation of bricks. Each brick is critical to the strength of that foundation, just as each employee contributes a skill that is critical to the corporation's success. And the mortar that holds us together is our vision statement with its emphasis on integrity and being a safe and great place to work.

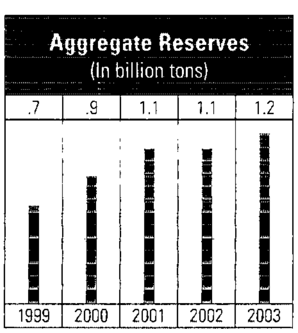
We survey our employees on a regular basis to keep working toward our goal of becoming a greater place to work. One issue that has surfaced from these surveys is our employees' desire for more opportunities for two-way communication. To help accomplish this objective, I made presentations to about 3,000 employees this year. Communication forums have been established in several locations where employees are encouraged to ask anything that's on their minds. In addition to the importance of achieving employee satisfaction, statistics show that companies that are officially designated as a Great Place to Work™ consistently outperform major stock indices.

We are focusing on the future by ensuring we have a solid succession plan in place. We have established a formal mentoring program that will be very valuable in the future in grooming successors at every level of the corporation.

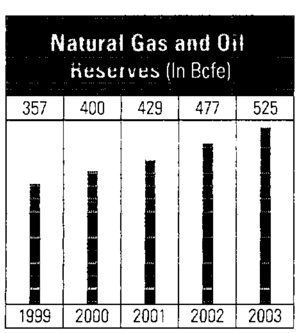
My greatest joy is working with the tremendous group of employees who commit themselves and their talents to operating this company. It has been a great year, and they are responsible for that success. I want to thank them for their dedication to this corporation as we help build a strong America. I am confident that we will work together to make our 80th anniversary year one that we will look back on with pride.

Martin A. White

Martin A. White
Chairman of the Board, President and Chief Executive Officer
Feb. 17, 2004



Recoverable aggregate reserves provide a solid foundation for future growth.



Proved natural gas and oil reserves have increased 47 percent since 1999.

Integrity is everyone's Responsibility

"It was clear to me that this company's integration of ethical principles into every level and every facet of its operations has made it a model of good corporate behavior."

These powerful words came from MDU Resources Lead Director Harry Pearce as he addressed employees in March 2003. "Clearly, we must build a culture of high performance and accountability, where leaders take personal responsibility for coaching, developing and driving performance, and team members take responsibility for their actions," he said. "Because whether you're leading a line crew or leading the Board of Directors, protecting a company's moral environment is everybody's business and everybody's responsibility."

MDU Resources takes pride in its corporate governance. The company has long fulfilled most of the new corporate governance requirements of the Securities and Exchange Commission and the Sarbanes-Oxley Act of 2002.

However, corporate governance is more than meeting the requirements of the law. The confidence and trust a company needs from its stakeholders cannot be legislated. Confidence and trust must be earned. Timely and accurate information to investors can establish realistic expectations for the future of the company. And, above all, a company must operate with integrity.

Corporate governance standards are continually evolving. New practices are adopted to meet and/or exceed new standards.

Practices adopted in 2003

- The Board of Directors affirmatively determined that all outside directors had no material relationship with the company and that they qualified as "independent" directors.
- Corporate governance guidelines and charters of the audit, compensation, finance, and nominating and governance committees were placed on the company Web site at www.mdu.com.
- The code of conduct for directors, officers and employees and the company's general guidelines on ethics are included on the Web site.
- SEC Forms 4 and 5, which report sales or purchases of company stock by officers and directors, are posted on the Web site.

Practices adopted prior to 2003

- Independent directors comprise a substantial majority of the board and one serves as lead director.
- Independent directors meet at regularly scheduled executive sessions without management.
- All Board committees are comprised solely of independent directors and have written charters addressing each committee's purpose and responsibilities.
- The company has an internal audit function and an audit committee with a minimum of three members who are financially literate.
- The Audit Committee regularly reviews interim quarterly and annual financial reports and the related independent auditors' report.
- The Audit Committee meets separately with management, independent auditors and internal auditors on a quarterly basis and reports regularly to the Board of Directors.
- A code of business conduct has been adopted, and all directors and executive officers have agreed to comply with the code.
- Shareholders have been given the opportunity to vote on stock-option plans.
- 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 2003 and 2002.
- 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, whose shares are gifted to the Annunciation Monastery and the University of Mary).
- Independent directors do not participate in the company's pension plan.

- The chief executive officer and the chief financial officer certify certain SEC filings made by the company.
- Updated and implemented disclosure controls and procedures are designed to ensure accurate and timely Exchange Act reporting and to support chief executive officer and chief financial officer quarterly and annual certifications.
- The 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.

The company will continue to work diligently to identify additional opportunities to improve its corporate governance practices and to ensure its internal controls meet the highest standards.

Employee initiatives

The company has numerous ongoing programs to help make employees aware of their responsibilities to act legally and with integrity. Employees are educated about various laws that apply to their organizations. They are encouraged to report any questionable practices or violations of law to their supervisors or other company personnel, including the business unit compliance officer, senior management and the Board of Directors. Employees are given guidance on several areas of ethical behavior. Those who work with international operations are provided guidance on compliance with applicable laws. In addition, all employees in management positions at all operating companies and at the corporate office annually sign a code of conduct.

"It was clear to me that this company's integration of ethical principles into every level and every facet of its operations has made it a model of good corporate behavior."

– Harry Pearce
MDU Resources Lead Director

Harry Pearce, lead director, spoke at the company's annual Leadership Conference regarding corporate governance.

Mary Hager, controller, right, and Nicole Kivisto, financial analyst, are part of the team implementing the Sarbanes-Oxley Act of 2002.

Trust
Confidence
Values
Employees
Leaders
Essential
Accurate
Code of Conduct
Initiatives
Diligent
Controls
Procedures
Reviews
Standards
Compliance
Sound
Disclosure
Responsibility
Assurance
Timeliness
Policies
Education
Laws
Foundation
80 Years
Citizen
Philanthropic
Performance
Service
Awareness
Honest
Strategies
Winner
Heroes
Efficiency
Innovation
Focus
Shareholders
Reliability
Pride
Cautious
Discipline
Safety
Dedication
Strength
Self-Control
Regulation
Model Behavior
Sense of Purpose
Ideology
Security
Truth
Justice
Adherence
Principles
Straight Forward
Upright
Great Place to Work
Commitment
Sincere
Quality

BOARD CHANGES

Dr. Joseph T. Simmons, a member of the Board of Directors since 1984, died in May 2003.

John K. Wilson was named to the Board of Directors in August 2003.

Patricia L. Moss was named to the Board of Directors in November 2003.

AUDIT COMMITTEE

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

COMPENSATION COMMITTEE

Harry J. Pearce, Chairman
Thomas Everist
Patricia L. Moss
Homer A. Scott, Jr.

FINANCE COMMITTEE

Robert L. Nance, Chairman
Thomas Everist
Dennis W. Johnson
Patricia L. Moss
Sister Thomas Welder, O.S.B.
John K. Wilson

NOMINATING AND GOVERNANCE COMMITTEE

John L. Olson, Chairman
Bruce R. Albertson
Robert L. Nance
Sister Thomas Welder, O.S.B.

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of Dec. 31, 2003.

Martin A. White, 62 (6)
Mandan, N.D.

Chairman of MDU Resources Board of Directors

President and Chief Executive Officer of MDU Resources

Harry J. Pearce, 61 (7)
Detroit, Mich.

Lead Director of MDU Resources Board of Directors

Retired, formerly chairman of Hughes Electronics Corp., a unit of General Motors Corp., and former vice chairman and director of General Motors; also serves as a director of numerous major corporations

Expertise: Multinational business management, engineering and law

Bruce R. Albertson, 58 (3)
Pompano Beach, Fla.

President and chief executive officer, Brown Jordan International, formerly president and chief executive officer of Iomega Corp. and vice president, marketing and product management worldwide of General Electric Co.

Expertise: Technology, marketing and international business

Thomas Everist, 54 (8)
Sioux Falls, S.D.

President and chairman of The Everist Co., 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, 54 (3)
Dickinson, N.D.

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

Expertise: Business management, engineering and finance

Patricia L. Moss, 50 (–)
Bend, Ore.

President and chief executive officer of Cascade Bancorp and Bank of the Cascades

Expertise: Finance and human resources

Robert L. Nance, 67 (11)
Billings, Mont.

President and chief executive officer of Nance Petroleum Corp., 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, 64 (19)
Sidney, Mont.

President and chief executive officer of Blue Rock Products Co. and Blue Rock Distributing Co., beverage manufacturing and distributing companies, and chairman of the board of Admiral Beverage Corp. with operations and franchises in the Rocky Mountain states

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

Homer A. Scott, Jr., 69 (23)
Sheridan, Wyo.

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

Expertise: Construction industry and banking

Sister Thomas Welder, O.S.B., 63 (16)
Bismarck, N.D.

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

John K. Wilson, 49 (–)
Omaha, Neb.

President of Durham Resources, LLC, a privately held financial management company, and president of Durham Foundation

Expertise: Finance and natural gas industry

Expanded biographies of all board members can be found in the 2004 MDU Resources Proxy Statement.

From left, front: *Bruce R. Albertson, Sister Thomas Welder and Patricia L. Moss.* Middle: *Dennis W. Johnson, Robert L. Nance, Thomas Everist and Martin A. White.* Back: *Harry J. Pearce, John L. Olson, John K. Wilson and Homer A. Scott, Jr.*

MANAGEMENT POLICY COMMITTEE

Martin A. White, 62 (12)
Chairman of the Board, President and Chief Executive Officer
MDU Resources

Serves on the company's 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, 49 (21)
President and Chief Executive Officer, WBI Holdings, Inc.

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 Co. and Montana-Dakota Utilities Co.

Terry D. Hildestad, 54 (29)
President and Chief Executive Officer
Knife River Corp.

Serves as chief executive officer of all construction materials and mining subsidiaries of Knife River; previously held management and executive positions with Knife River

Numbers indicate age and years of service ( ) as of Dec. 31, 2003.

Lester H. Loble, II, 62 (16)*
Executive Vice President, General Counsel and Secretary
MDU Resources

Served as general counsel and secretary for all major company subsidiaries; previously engaged in the private practice of law

Cindy C. Redding, 45 (1)
Vice President–Human Resources, MDU Resources

Serves as human resources leader for the corporation; previously held domestic and international human resources management positions in the energy, health care and global packaging industries with several major corporations

Warren L. Robinson, 53 (15)
Executive Vice President and Chief Financial Officer, MDU Resources

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

Ronald D. Tipton, 57 (20)
Chief Executive Officer, Montana-Dakota Utilities Co., Great Plains Natural Gas Co. and Utility Services, Inc.

Serves as chief executive officer of all utility services subsidiaries; previously served as president of Montana-Dakota, Great Plains and USI; also served as president and chief executive officer of Williston Basin Interstate Pipeline Co. and in various executive and management positions; and in executive and management positions with two other energy and natural gas corporations

MANAGEMENT CHANGES

Mary B. Hager was named controller and Floyd E. Wilson was named vice president–strategic planning and corporate development effective May 15, 2003. Richard A. Espeland retired as vice president–human resources on July 1, 2003. Cindy C. Redding was named to replace him as vice president–human resources. Daryl A. Splichal was named treasurer effective Jan. 1, 2004.

**Lester H. Loble, II, executive vice president, general counsel and secretary, retired effective Jan. 2, 2004. Cynthia J. Norland was named acting general counsel and acting secretary effective on his retirement.*

CORPORATE OFFICERS

Martin A. White, 62 (12)
Chairman of the Board, President and Chief Executive Officer

Cathleen M. Christopherson, 59 (36)
Vice President–Corporate Communications

Mary B. Hager, 40 (10)
Controller

Lester H. Loble, II, 62 (16)*
Executive Vice President, General Counsel and Secretary

Vernon A. Raile, 58 (23)
Senior Vice President and Chief Accounting Officer

Cindy C. Redding, 45 (1)
Vice President–Human Resources

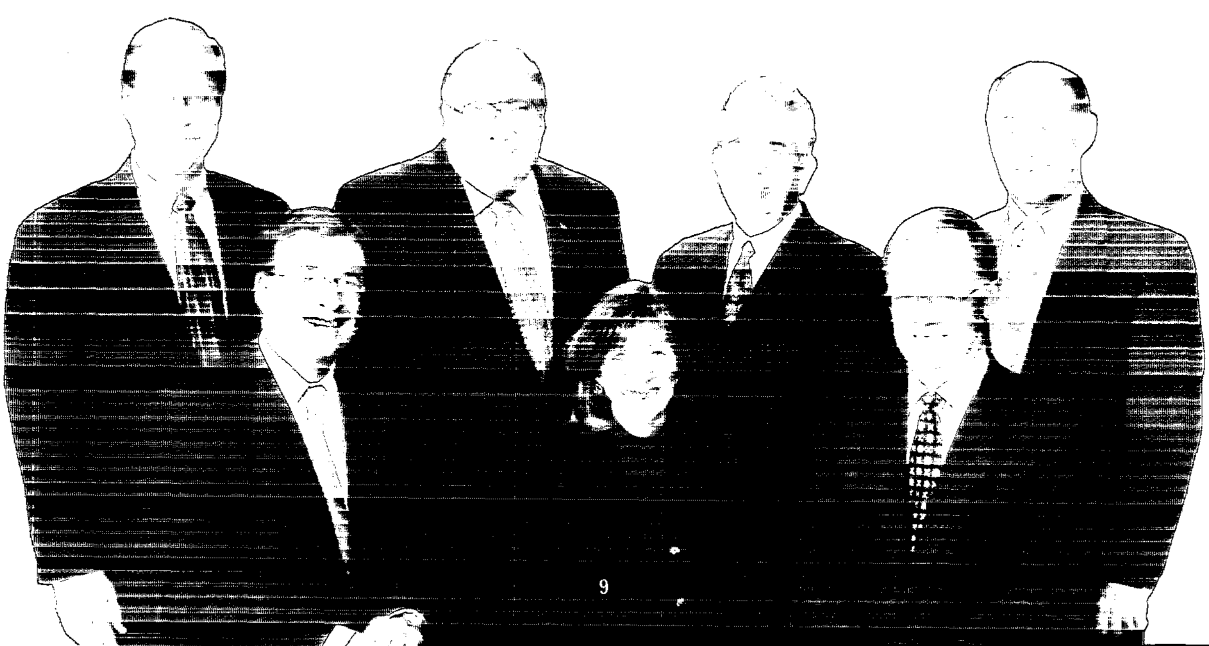
Warren L. Robinson, 53 (15)
Executive Vice President and Chief Financial Officer

Daryl A. Splichal, 48 (23)
Treasurer

Floyd E. Wilson, 53 (22)
Vice President–Strategic Planning and Corporate Development

Robert E. Wood, 61 (29)
Vice President–Public Affairs and Environmental Policy

From left, front: *Terry D. Hildestad, Cindy C. Redding and Martin A. White.* Back: *John K. Castleberry, Warren L. Robinson, Ronald D. Tipton and Lester H. Loble, II.*



Fuel for America

An aggressive drilling program has increased Fidelity Exploration & Production's natural gas and oil production, providing a valuable domestic source of fuel for the United States. The company exceeded last year's level of production while also adding to its reserve base of natural gas and oil, promising a continuing source of domestic energy.

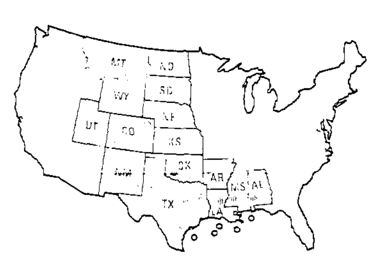
Total natural gas and oil production increased by 10 percent in 2003, exceeding 2002 record levels and creating a new company benchmark. Fidelity drilled 288 wells during 2003, compared to 205 wells in 2002, when an industry publication ranked it one of the most active drillers in the nation. The wells drilled are on a net basis, which reflects the company's well ownership share.

All energy-producing companies strive to increase production while growing reserves. Fidelity's program to replace produced reserves by applying new techniques to its production areas, along with an active development drilling program, has been successful in increasing reserves. Proved natural gas and oil reserves increased to 525 billion cubic feet equivalent, as compared to 477 Bcfe in 2002. The company is conservative when including reserves in its estimation of year-end reserves. Proved undeveloped reserves at year-end 2003 were only 18 percent of total proved reserves. And the majority of these proved undeveloped reserves is in long-lived producing areas with an extensive history of production and reserve success.

The company's net lease position in Montana, Wyoming and Colorado exceeds 1.0 million acres. This acreage position represents a huge potential resource for the company and will allow continued exploration, development and growth for the next five to 10 years.

Environmental stewards

Fidelity was the first producer of coalbed natural gas in Montana.



o Area of principal production and reserves

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 and around the Gulf of Mexico.

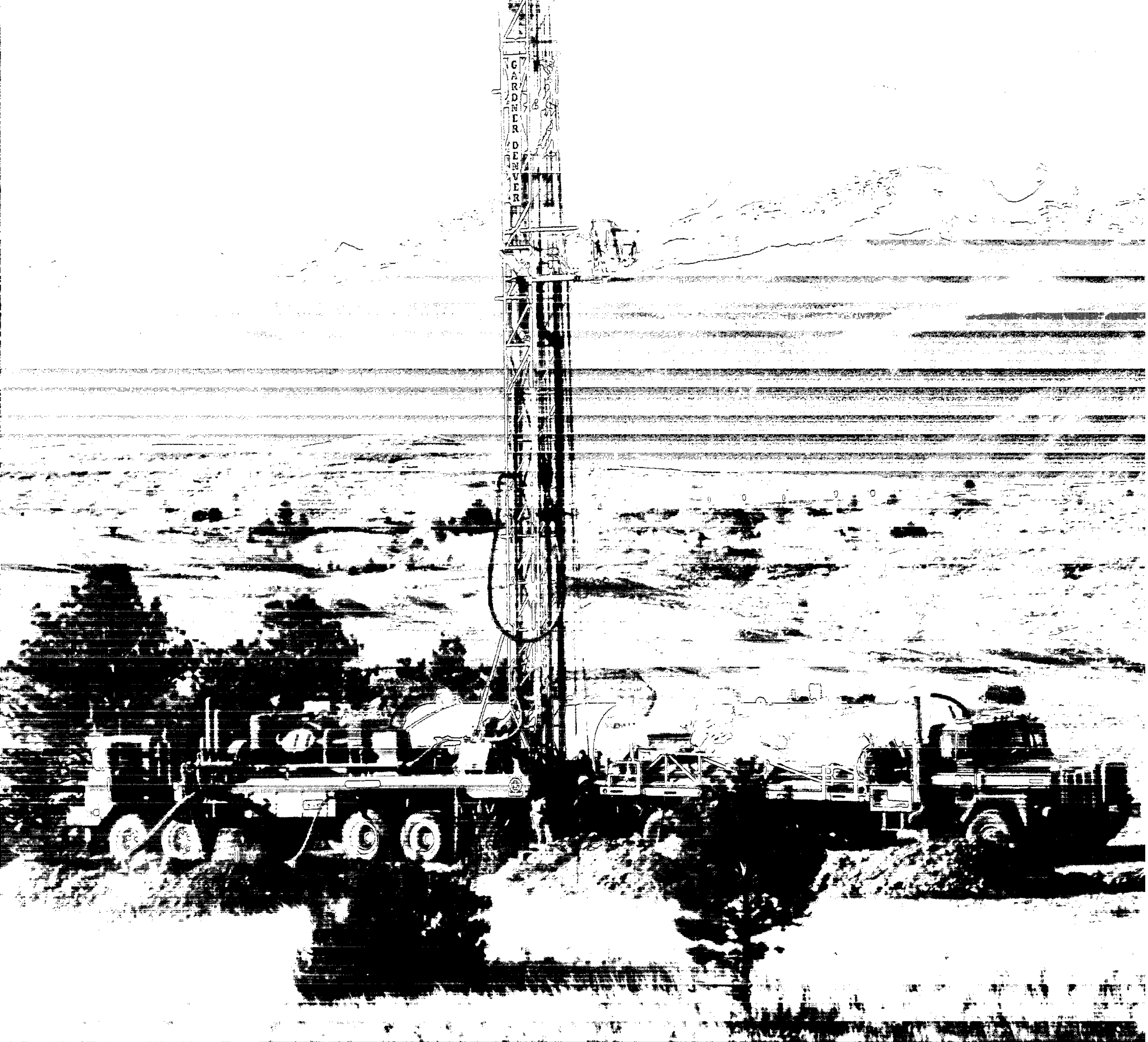
Managing the water produced in conjunction with natural gas is a controversial issue. The company is leading the way in water management solutions.

At a company-owned ranch near one of its producing fields, Fidelity is researching the use of water on different forage crops by making use of various irrigation methods and soil additives. The company is also sponsoring a soil- and crop-testing program for landowners throughout the Tongue River watershed in the Powder River Basin to gather information on potential impacts to soil and water conditions. The program will help determine any long-term impact from water discharges into streams and rivers associated with the use of the produced water.

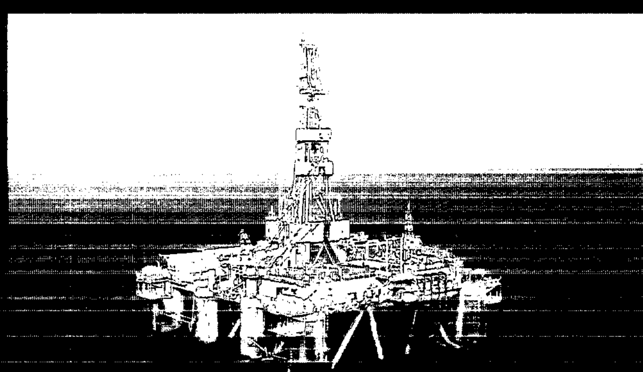
Foundation and future

Fidelity has strategically accumulated its unique combination of assets to minimize risk. The company attempts to hedge approximately 50 percent of its annual natural gas and oil production to minimize the effects of fluctuations in commodity prices. Because the company operates in different geographic areas, its products access different markets, thus reducing dependence on a single pricing regimen.

The company has a strong foundation in long-lived properties that produce consistent and stable cash flow. These properties, combined with new reserves acquired and developed in recent years, create a dynamic future for Fidelity.



Production from long-held gas fields in eastern and northern Montana has grown by nearly 300 percent since 1995.



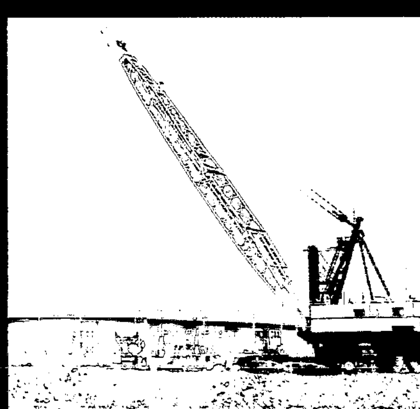
Fidelity balances its Rocky Mountain-based production activities with offshore development in the Gulf of Mexico accomplished through operating partnerships.

^
The company began expanding coalbed natural gas production in Montana midyear after the finalization of an expansive environmental impact study.

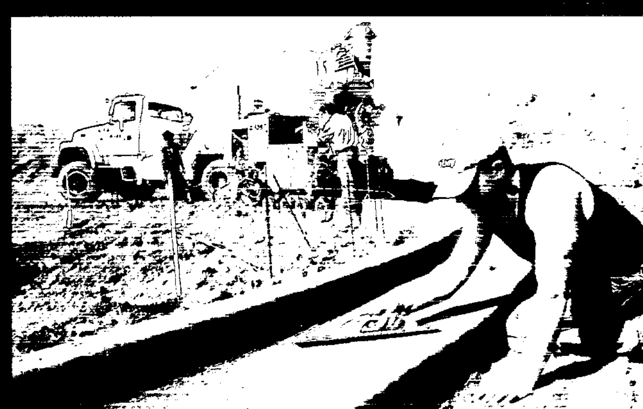
Production and reserves increase **10 percent**

^
Knife River acquired Young Contractors, with headquarters in Waco, Texas, in July.

Revenues set new record at **$1.1 billion**



Connolly-Pacific continues work on its portion of a $180 million joint-venture harbor deepening project in the Port of Los Angeles.



Knife River acquired Atlas, with headquarters in Bismarck, N.D., and Pioneer Construction, with headquarters in Mandan, N.D., in April.

Solid as a Rock

The heart of Knife River is its 1.2 billion tons of aggregate reserves. The soul of the company is its nearly 3,600 employees. The heart and soul of MDU Resources' construction materials and mining division combine to provide the products and services that build America's infrastructure.

2003 marked Knife River's fourth consecutive record year in earnings and revenues. Last fall the company hit a milestone by topping $1 billion in annual sales, which was marked with celebrations across company locations.

Expanding operations

Knife River continues to expand its geographic diversity. Having acquired several companies, it now has operations in 10 states. A company acquired in April in Kalispell, Mont., was combined with existing operations in Montana. Two companies acquired in April in North Dakota and acquisitions in Iowa and Minnesota in February 2004 add to the company's Midwest footprint. A sizeable Texas company that was acquired in July adds operations that are less affected by seasonal weather changes.

Knife River's growth in the aggregate business has placed it among the Top 10 aggregate producers in America, according to the U.S. Geological Survey. Knife River intends to continue to expand its operations through strategic acquisitions and operational excellence.

Business booming

Rapid home building has kept the construction materials and mining division busy and was one of the factors contributing to Knife River's record year. Markets in central California and central Minnesota have seen especially high development.

A harbor deepening project in Los Angeles was one of the company's largest projects this year. Connolly-Pacific supplied the rock for this project.

Operations in Alaska and Hawaii continued to benefit from the strong economies in those states. Commercial construction projects, as well as work on military installations, contributed to the growth Knife River's operations experienced in these states.

Operations in the Rocky Mountains and on the Oregon coast focused mainly on highway construction projects. Resort and residential community development are mainstays for the central Oregon operations. Precast concrete is an important component of the products Knife River's Oregon companies provide for use in both highway bridges and commercial buildings.

○ Construction materials locations

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 performs integrated construction services, in the central and western United States, and in the states of Alaska and Hawaii.

Challenges equal opportunities

Knife River is confident that Congress will approve federal legislation that will fund transportation at levels equal to or higher than funding approved by previous legislation. Legislation has the potential to affect the availability of federal, state and local contracts.

Obtaining permits to allow aggregate reserves to be mined continues to be a challenge in some areas of operation. Fortunately, the company has about 1.2 billion tons of reserves, most of which are permitted, located throughout its operational areas. These reserves are estimated to last the company more than 30 years at current production rates.

Reliable supplier of Energy

Providing safe, reliable electricity and natural gas services to more than 295,000 customers in five states is the hallmark of Montana-Dakota and Great Plains. Investing in technology, offering value-added energy products and services, and paying close attention to cost control help enhance shareholder value and allow customers to enjoy low-cost service.

Winter and summer weather extremes, combined with aggressive marketing, produced increases in sales of both natural gas and electricity when compared to the previous year. A new electric system peak of 470.5 megawatts, driven by growing air conditioning load, was set. This is an increase of 12 MW. In May, a natural gas-fueled combustion turbine at Glendive, Mont., was placed on line, helping to meet peak demand and satisfy reserve requirements of the regional power pool.

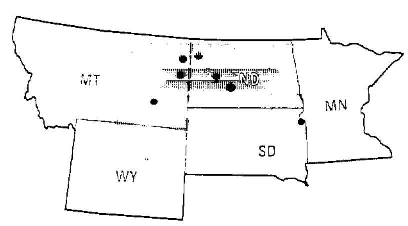
Sales growth

Coal-fueled, base-load power plants offer low-cost, competitively priced electricity to off-system customers. Off-system electricity sales increased over the previous year. A North Dakota electric rate filing in May was settled in December, adding $1 million additional annual revenues. The settlement also established a mechanism through which the company shares income from off-system sales with its retail customers.

A return to more seasonal winter temperatures, combined with modest rate increases in the company's Minnesota, Montana, North Dakota and South Dakota jurisdictions, provided a fair return on natural gas services to shareholders while maintaining reasonable prices to customers. Customers enjoy supply reliability from regional natural gas reserves and access to large natural gas storage fields. More than 3,400 new customers were added in 2003, principally in growth areas surrounding Billings, Mont., Bismarck, N.D., and Rapid City, S.D.

Expanded services

Since it was founded in 1924, Montana-Dakota has offered customers value-added energy services. Today, the company offers appliance sales and service, appliance maintenance contracts and a home security service. The company also provides utility construction, operation and maintenance services for facilities owned by others. Activity in each of these nonregulated areas increased in 2003. Aggressively pursuing nonregulated earnings provides for more efficient use of company facilities and resources, benefiting customers and shareholders alike.



○ Electric and natural gas distribution area
● Electric generating stations

Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Great Plains Natural Gas Co. serves natural gas customers in western Minnesota and southeastern North Dakota. These operations also supply related value-added products and services.

To ensure that its customers have reliable service at competitive rates is one of the company's goals. The company invests in its own generation and constantly monitors its need for future generation. It is committed to purchasing dependable, low-cost natural gas supplies.

Montana-Dakota and Great Plains will continue to provide customers the electricity and natural gas they need and use every day. The companies will look for further opportunities to grow through value-added services and possible acquisitions.

^
Rick Patzman helped with the addition of a 40-MW combustion turbine, which will ensure reliable electric service.

Electric and natural gas earning increase more than 7 percen

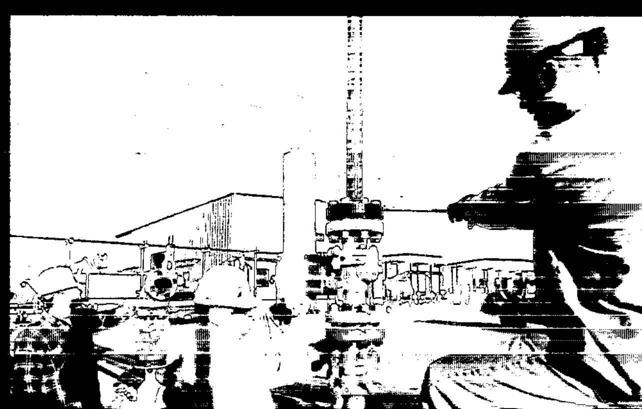
Curt Olson is one of many service representatives who provide customers with first-rate, value-added energy services.

Sound marketing programs added more than 3,400 natural gas customers during 2003. Wade Wasserburger is one of many employees who made this happen.

^
Completion of Williston Basin's 253-mile Grasslands Pipeline adds value by increasing the company's overall natural gas delivery capabilities.

Peak day pipeline capacity increases **18 percent**

Pat Skillestad, staff engineer, helped Bitter Creek add compressor facilities to keep pace with increasing natural gas production.



A compressor station was constructed in western North Dakota as part of the new Grasslands Pipeline, which moves Rocky Mountain produced gas to mid-continent markets.

Pipeline to the Heartlands

WBI Holdings has transmission and gathering pipelines throughout some of the most promising natural gas production areas in the country. The company is aggressively working to add additional facilities and services to the region to help deliver this valuable energy to America's marketplace.

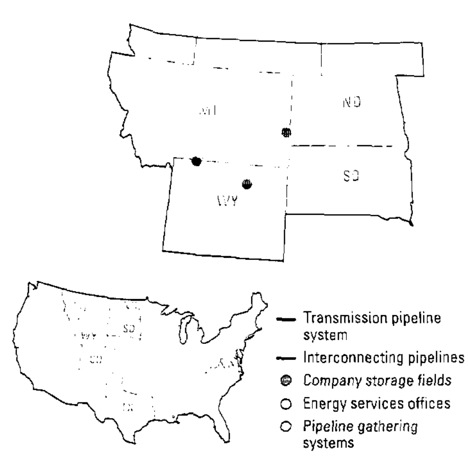
WBI Holdings is focused on the future, as evidenced by the completion of a massive pipeline project and significant new additions to compression and gathering pipeline facilities in key natural gas production areas in 2003.

Pipeline expansion

Williston Basin Interstate Pipeline constructed the Grasslands Pipeline in the third and fourth quarters of 2003. The 253-mile, 16-inch natural gas pipeline spans sections of Wyoming, Montana and North Dakota. The pipeline project is the largest ever undertaken by the company. Grasslands will transport natural gas from the Rocky Mountain region to interconnecting pipelines, which will deliver it to large Midwest markets. The pipeline also is connected to the company's vast natural gas storage system in eastern Montana, which allows large-volume customers to take advantage of seasonal market price fluctuations.

Placed in service in late December, Grasslands is currently capable of transporting 90 million cubic feet of natural gas per day on a firm basis. Additional firm capacity can be added in phases as natural gas production grows in the Rocky Mountain region.

Bitter Creek Pipelines also has added to its gathering systems and compression facilities to access the increasing natural gas production in the Rocky Mountain region.



WBI Holdings, Inc., through various subsidiaries, 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.

Energy services

Research and development of technologies and services related to the pipeline and energy industries are key areas of growth. Two of its operations, Innovatum and SubSurface Instruments, have worldwide expertise in locating and tracking underwater and underground oil and gas pipelines, electric power cables and fiber optic cables. The continuous development of new technologies and services, along with ongoing work in energy efficiency systems, provide a diverse revenue stream.

Future focus

The company enjoys a significant competitive advantage originating from the expertise of its employees. WBI Holdings' leaders believe that respectful communication builds employee relationships. Regularly scheduled informational meetings and an annual Communication Forum enhance these relationships. The company is committed to being a continuous learning enterprise, offering numerous training and development programs.

Business strategy includes maximizing the use of existing assets and growth through a disciplined approach to acquisition and construction of similar business assets. In an era marked by increasing demand for natural gas, WBI Holdings is well positioned to continue to deliver this fuel to the marketplace.

Make the Connection

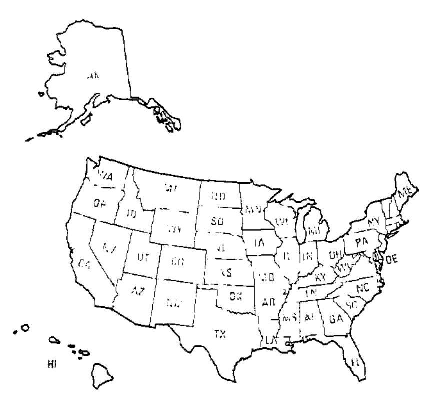
Whether building a pipeline in Oregon, wiring a factory in Ohio or stringing electric conductor in Colorado, Utility Services, Inc. companies have one thing in common – they offer infrastructure support to keep their customers strong and viable. Geographic and service diversity within USI helps promote stability in changing economic times. Established in 1997, USI companies are authorized to do business in 43 states.

2003 illustrates how solid companies can maintain market share and survive in a down economy. The company capitalized on its diversity and as a result contributed positively to corporate earnings. USI continues to search for well-managed companies to acquire in high-growth areas.

Diverse operations

While activity in the inside electrical contracting industry remained depressed for the second straight year, USI companies in the St. Louis and Cincinnati metropolitan areas were successful bidders on several large wiring and cabling jobs. As the economy rebounds, USI expects to see an increase in demand for inside electrical work as delayed new building construction and maintenance projects materialize.

Capital Electric Line Builders' completion of the $25 million Kansas City Scout Project, a 75-mile traffic management system, gives the company valuable expertise in planning and installing "smart highway" systems. Completing its part of the Scout Project on time and on budget positions USI for future projects as the nation's metropolitan areas struggle with growing traffic management issues.



○ Utility services offices
State names indicate authorized states of operation

Utility Services, Inc. companies offer utilities and large manufacturing, commercial, government and institutional customers a diverse array of products and services. USI specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling and the manufacture and distribution of specialty equipment.

Late summer and early fall wild fires in southern California added significantly to Pouk & Steinle's workload. The Riverside, Calif.- based company replaced hundreds of transmission poles and other transmission facilities destroyed by fire. Pouk & Steinle also added a subsurface structure division that will help the company secure more overhead-to-underground conversion work in the Anaheim, Calif., area.

USI companies operating in the western United States secured transmission structure replacement contracts with several regional utilities. Manufacturing and leasing electrical line equipment also remain important aspects of this business.

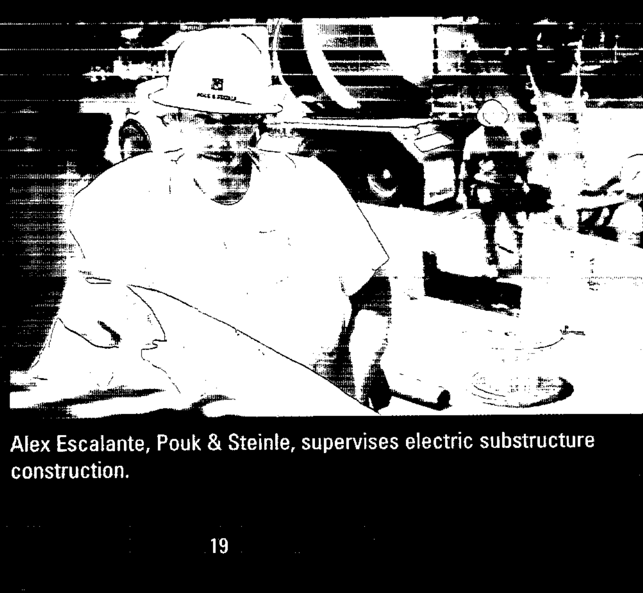
Quality reputation

USI supports passage of a comprehensive national energy bill that includes reliability standards and tax incentives designed to upgrade the nation's aging electrical transmission grid. USI companies in the western United States possess a reputation for expertise in high-line construction and upgrading.

Whatever the job, each USI company relies on strong management and experienced, dedicated employees to get the job and get it done right.

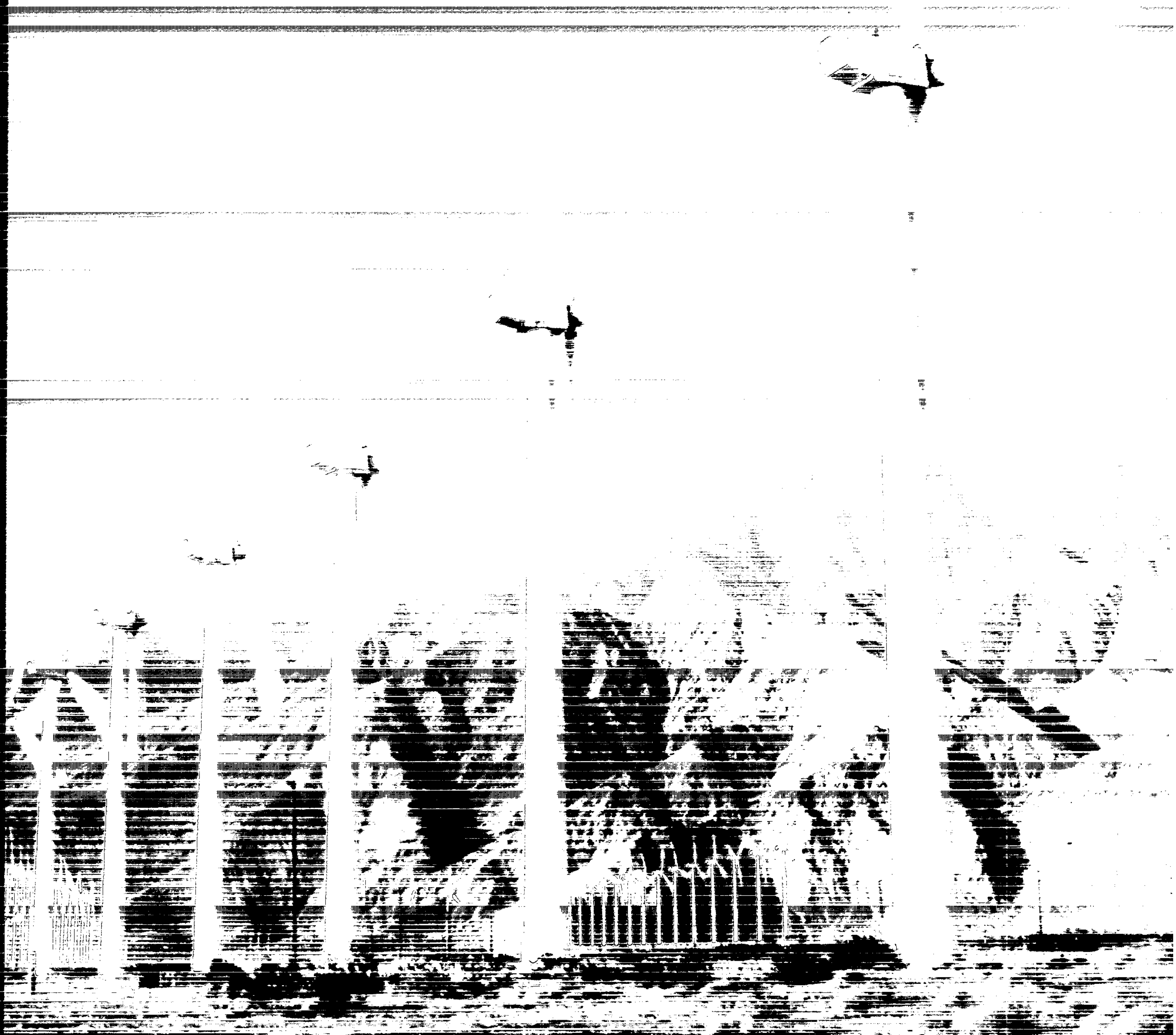
Maintaining electric transmission poles is Hamlin Electric's Chet Austin's job.

Bob Cannon, Bell Electrical Contractors, is part of the team that installs electric service to all types of industrial and commercial facilities.



Alex Escalante, Pouk & Steinle, supervises electric substructure construction.

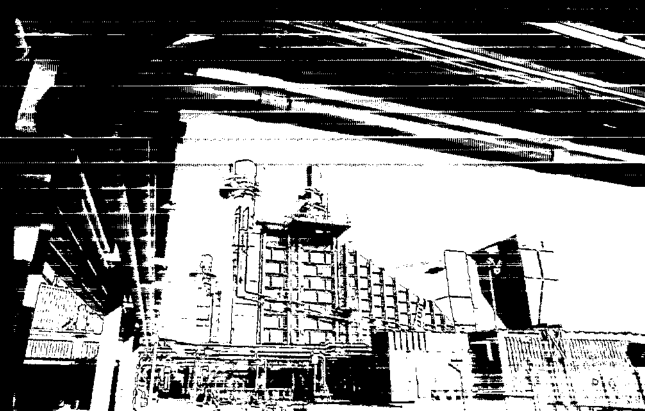
Earnings steady at **$6.2 million**



A wind facility near Palm Springs, Calif., sells its output to the California Department of Water Resources.

Earnings total **$12 million** in first full year of operation

A natural gas-fired electric generating facility in northeastern Brazil is serving as a platform for international growth.



Capitalizing on the growing Denver metropolitan area, Centennial Energy purchased a natural gas-fired electric generating facility in Brush, Colo.

Power for the Future

Centennial Energy is MDU Resources' newest business unit. Centennial Energy invests internationally in natural resource-based projects and domestically in independent power production ventures.

The evolution of Centennial Energy's strategy began in 2001. Since then, the company has achieved rapid growth by developing or acquiring 500 megawatts of electrical generating facilities in three states and Brazil. In 2003, it contributed $12 million in earnings to the corporation.

Centennial Energy's portfolio includes a 49 percent interest in MPX Participacoes Ltda, which owns a 220-MW natural gas-fired electrical generating facility in northeastern Brazil; Brush Power, a 213-MW natural gas-fired electrical generating facility in Brush, Colo., and Mountain View Power Partners, a 66.6-MW wind facility near Palm Springs, Calif. It also includes Rocky Mountain Power, a 113-MW coal-fired electric generating facility under construction near Hardin, Mont., projected to be completed in late 2005. This project is being constructed as a merchant plant; however, the company expects to have a long-term contract in place by the time the project is completed.

These projects reflect the fundamental philosophy that drives Centennial Energy – to seek opportunities that capitalize on long-term contracts or unique development prospects through a diverse array of resource types, both in the United States and globally.

International interests

MPX Participacoes completed its first full year of operation in 2003. This project, Centennial Energy's first endeavor in a foreign market, is a joint venture with Brazilian partner EBX Capital. Capacity and energy are sold under a long-term contract with Petrobras, Brazil's largest industrial company and one of the world's large petroleum producers. This project has been a positive investment and will serve as a platform for international growth.

Domestic interests

Domestically, 2003 brought intense competition and new players into the acquisition market for low-risk projects with long-term contracts. The competition increased the cost of acquisitions, resulting in lower potential projected returns on investments.

Centennial Energy has maintained its disciplined acquisition strategy and, except for Mountain View which was acquired in January 2003, did not find any other major projects that met its criteria. Instead, it focused its efforts on fully integrating its operations under one management system, better preparing itself for the return of more favorable markets.

Centennial Energy is continually evaluating multiple projects that represent thousands of megawatts of potential acquisition or development opportunities. Some of these opportunities complement existing operations, while others provide openings to expand into new markets. Through its strategies and increasing world knowledge, the company is poised to capitalize on solid opportunities whenever and wherever they arise.

Centennial Energy Resources owns electric generating facilities in the United States and has investments in South America. Electric capacity and energy produced at its power plants primarily are sold under long-term contracts to nonaffiliated entities. These operations also include investments not directly being pursued by the corporation's other businesses.

Building strong Communities

Cindy Baker, district customer service representative for Great Plains, organized an employee team for the Relay for Life in her community of Granite Falls, Minn. Relay for Life raises money for the American Cancer Society.

The MDU Resources Foundation helps sponsor many charitable and arts groups, including the Central Dakota Children's Choir. The group gives budding artists an opportunity to participate in quality choral singing. There is a tuition fee, but scholarships are available thanks to donations from companies like MDU Resources.

Brian Voss, operations specialist for Williston Basin, his wife, Stephanie, and daughter, Elizabeth, enjoy fishing from a newly constructed pier in Worland, Wyo. Williston Basin employees helped design and build the handicapped accessible pier and fishing pond.

Building strong communities is the foundation of Building a Strong America. MDU Resources continuously demonstrates its commitment to building strong communities by being a good corporate citizen and a good neighbor. Giving back to the communities where its employees live and work is one small demonstration of the corporation's commitment to the communities that support its businesses.

The corporation gives back

In 2003, the corporation marked the 20th anniversary of the MDU Resources Foundation, the philanthropic arm of MDU Resources and its affiliated companies. Since incorporation, the foundation has contributed more than $6 million to qualified charities and organizations throughout the United States. All recipients of foundation funding must be recognized by the Internal Revenue Service as qualified recipients under section 501(c)(3) of the Internal Revenue Code.

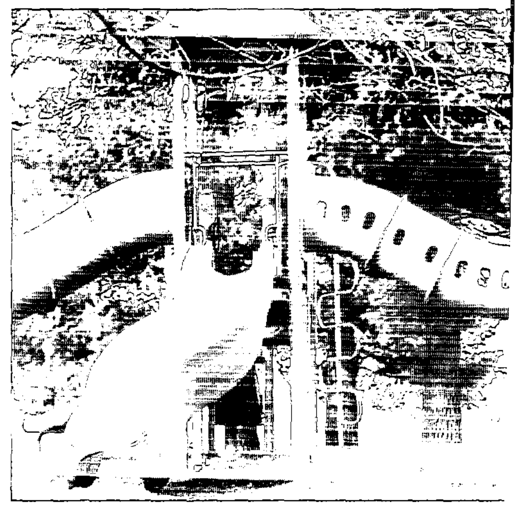
With its contribution budget surpassing $1 million annually, in 2004 the foundation will provide grants to more than 350 organizations within the corporation's vast service territories. Each of the operating companies provides funding based on a portion of each company's pre-tax net income. Grants typically range from $500 to $25,000 annually.

As the company has grown, the foundation has expanded its commitment and contributions to areas where the corporation has new business interests. A few examples are as follows:

Being a good corporate citizen and a good neighbor is not just the right thing to do – it is our way of life.

Joe Icenogle, regulatory affairs manager of Fidelity, delivers beef to Mary Gwen Brayton, a volunteer at the Lunch Together Soup Kitchen in Sheridan, Wyo. This is the third consecutive year that Fidelity has donated to the program.

The University of Montana-Billings is just one of many higher-education institutions that receives funding through company and employee donations.



A city park in Wahkon, Minn., is just one of many parks that benefits from the Partners in Parks program. The MDU Resources Foundation awards grants to the program, which provides funding for updating and beautifying parks throughout Minnesota.

- $100,000 to CentraCare Health Systems in St. Cloud, Minn., for the construction of a cancer care facility;
- $45,000 to the Oregon Burn Center in Portland for a construction project;
- $20,000 to the Idalia, Colo., Ambulance Service to assist with the purchase of a new ambulance;
- $10,000 to the Boy Scouts of America in Tomball, Texas;
- $9,000 to the Chico Museum of Natural History in Chico, Calif.;
- $6,000 to the Montgomery County Historical Society in Dayton, Ohio;
- $5,000 to the Maui, Hawaii, United Fund; and,
- $4,000 to the Alaska Food Bank in Anchorage.

The foundation manages three education funding programs. Two are aimed at higher education, with a third program intended for education at all levels. The first is a scholarship program, which provides funding for scholarships at more than 30 colleges and universities, with funding also for construction projects on a half dozen campuses. A second program provides higher-education scholarships for the children and/or spouses of employees. A third program matches, on a limited basis, the personal contributions of employees to private and public elementary, secondary and higher-education institutions.

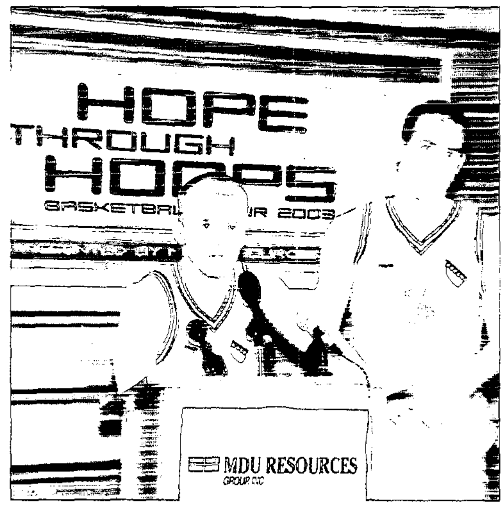
Employees contribute time and expertise

In addition to the organizations supported financially by the foundation, individual employees contribute in countless ways to make our communities better places in which to live by donating their personal resources, time and expertise to worthwhile organizations and projects. Many employees give generously to United Way, serve on boards of charitable and arts organizations, coach sports teams, as well as serve on city commissions and volunteer fire departments. Many are involved with Habitat for Humanity and Christmas in April, both of which help provide housing for low-income people. Still others serve on school boards, chambers of commerce and hospital boards.

The foundation will provide grants to more than 350 organizations within the corporation's vast service territories.

Phil Lisciandra, journeyman IBEW Local #1, (Bell Electrical), worked on remodeling a former "drug house" in St. Louis, Mo. A local church is updating houses in the neighborhood one by one. Bell crews completed the inside electrical work.

Like many employees who also are members of the National Guard, Jerry Lang, an employee of Bauerly Brothers in St. Cloud, Minn., is answering the call of duty. Lang, a colonel in the National Guard, is presently serving in Bosnia.



Adi Mujkanovic, left, and Enes Hadzihalilovic respond to reporters' questions during Media Day for the Hope through Hoops Basketball Tour 2003. MDU Resources sponsored the upper Midwest segment of the tour and played host to 15 members of the Coaching Association of Bosnia-Herzegovina.

The 2003 winner of the corporation's Community Spirit Award was Walt Miyashiro, an employee of Hawaiian Cement. Miyashiro was honored for his tireless work in promoting soccer on the island of Oahu, as well as his commitment to the Big Brother/Big Sister program in his community of Pearl City, Hawaii.

MDU Resources has its heroes

Employees are also not afraid to use their emergency training to help others off the job. In Rapid City, S.D., Montana-Dakota serviceman John Miller used his CPR training to save the life of a 16-year-old boy who had been struck by lightning. It is the third time Miller has used his first aid training to save another.

In Chico, Calif., Baldwin Contracting Company's Culvin May, assistant dispatcher, came upon a motor vehicle accident. Climbing down a 40-foot embankment, May helped the vehicle occupants to safety, applied a tourniquet made from his shirt to the bleeding arm of one of the victims, flagged down assistance from a passing motorist and then waited with the couple until an ambulance arrived.

Many employees have been deployed with their National Guard or Army Reserve units to serve their country far from home. These men and women are truly heroes, for they have interrupted and are risking their lives to improve the lives of others.

At MDU Resources, being a good corporate citizen and a good neighbor is not just the right thing to do – it is our way of life. Whether it is through contributions made by the corporation or by individual employees, the MDU Resources family of companies believes in Building Strong Communities while Building a Strong America.

OVERVIEW

This subsection of Management's Discussion and Analysis is a brief overview of the important factors that management focuses on in evaluating MDU Resources Group, Inc.'s (Company) businesses, the Company's financial condition and operating performance, the Company's overall business strategy and the earnings of the Company for the period covered by this report. This subsection is not intended to be a substitute for reading the entire Management's Discussion and Analysis section. Reference is made to the various important factors listed under the heading Risk Factors and Cautionary Statements that May Affect Future Results, as well as other factors that are listed in Part I in the Company's 2003 Form 10-K in relation to any forward-looking statement.

Business and Strategy Overview

The Company has six reportable 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 separated independent power production and other operations from its reportable segments. The independent power production and other operations do not individually meet the criteria to be considered a reportable segment. Substantially all of the operations of independent power production and other began in 2002; therefore, financial information for years prior to 2002 has not been presented.

The electric and natural gas distribution segments include the electric and natural gas distribution operations of Montana-Dakota Utilities Co. (Montana-Dakota) and the natural gas distribution operations of Great Plains Natural Gas Co. (Great Plains). The utility services segment includes all the operations of Utility Services, Inc. The pipeline and energy services segment includes WBI Holdings, Inc.'s (WBI Holdings) natural gas transportation, underground storage, gathering services, and energy-related management services. The natural gas and oil production segment includes the natural gas and oil acquisition, exploration and production operations of WBI Holdings. The construction materials and mining segment includes the results of Knife River Corporation's (Knife River) operations. Independent power production and other operations own electric generating facilities in the United States and have an investment in an electric generating facility in Brazil and investments in opportunities that are not directly being pursued by the Company's other businesses.

Earnings from electric, natural gas distribution, and pipeline and energy services are substantially all from regulated operations. Earnings from utility services, natural gas and oil production, construction materials and mining, and independent power production and other are all from nonregulated operations.

On August 14, 2003, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 11 of Notes to Consolidated Financial Statements.

The Company's strategy is to pursue growth opportunities by expanding upon its expertise in energy and transportation infrastructure industries, focusing on acquiring and developing well-managed companies and projects that enhance shareholder value and are accretive to earnings per share and returns on invested capital.

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. In addition, earnings per share for 2004, diluted, are projected in the range of $1.55 to $1.68. Contributing to the anticipated growth goals and/or earnings per share projections are a number of items including:

- Expected returns in 2004 at the electric business are anticipated to be generally consistent with authorized levels.
- The Company expects to seek natural gas rate increases from time to time to offset higher expected operating costs at the natural gas distribution business.
- Anticipated increased margins in 2004 compared to 2003 at the utility services business.
- An expected increase of total natural gas throughput of approximately 25 percent to 30 percent over 2003 levels at the pipeline and energy services business, largely due to the 253-mile Grasslands Pipeline, which began providing natural gas transmission service on December 23, 2003.
- Transportation rates are expected to decline in 2004 from 2003 levels due to the estimated effects of a Federal Energy Regulatory Commission (FERC) rate order received in July 2003.
- An expected natural gas and oil production increase of approximately 10 percent in 2004 compared to 2003.
- Natural gas prices in the Rocky Mountain region for February through December 2004 reflected in the Company's 2004 earnings guidance are in the range of $3.25 to $3.75 per Mcf. The Company's estimates for natural gas prices on the NYMEX for February through December 2004, reflected in the Company's 2004 earnings guidance, are in the range of $4.00 to $4.50 per Mcf.
- The Company has hedged a portion of its 2004 estimated annual natural gas production. The Company has entered into agreements representing approximately 30 percent to 35 percent of 2004 estimated annual natural gas production. The agreements are at various indices and range from a low CIG index of $3.75 to a high CIG index of $5.48 per Mcf. CIG is an index pricing point related to Colorado Interstate Gas Co.'s system.
- NYMEX crude oil prices for January through December 2004, reflected in the Company's 2004 earnings guidance, are in the range of $26 to $30 per barrel.
- The Company has hedged a portion of its 2004 oil production. The Company has entered into agreements at NYMEX prices with a low of $28.84 and a high of $30.28, representing approximately 30 percent to 35 percent of 2004 estimated annual oil production.

- An expected increase in 2004 revenues of approximately 5 percent to 10 percent over 2003 levels at the construction materials and mining business.
- Anticipated earnings in the range of $18 million to $23 million in 2004 at the independent power production and other businesses.

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper credit facilities and through the issuance of long-term debt and the Company's equity securities. Net capital expenditures for 2003 were $474 million and are estimated to be approximately $370 million for 2004.

The Company faces certain challenges and risks as it pursues its growth strategies, including, but not limited to the following:

- The natural gas and oil production business experienced higher average natural gas and oil prices in 2003 compared to 2002. These prices are volatile and subject to significant change at any time. The Company hedges a portion of its natural gas and oil production in order to mitigate price volatility.
- The soft economy and the depressed telecommunications market have been challenging particularly for the Company's utility services business, which has been subjected to lower margins and decreased workloads. These economic factors have also negatively affected the Company's energy services business.
- Fidelity Exploration & Production Company (Fidelity) continues to seek additional reserve and production growth through acquisition, exploration, development and production of natural gas and oil resources, including the development and production of its coalbed natural gas properties. Future growth is dependent upon success in these endeavors. Fidelity has been named as a defendant in, and/or certain of its operations are the subject of, 11 lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material effect on Fidelity's existing coalbed natural gas operations and/or the future development of its coalbed natural gas properties.

For further information on certain factors that should be considered for a better understanding of the Company's financial condition, see the various important factors listed under the heading Risk Factors and Cautionary Statements that May Affect Future Results, as well as other factors that are listed in Part I of the Company's 2003 Form 10-K.

For information pertinent to various commitments and contingencies, see Items 1 and 2 – Business and Properties and Item 3 – Legal Proceedings in the Company's 2003 Form 10-K, as well as Notes to Consolidated Financial Statements.

Earnings Overview

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

Years ended December 31,	**2003**	2002	2001
	(Dollars in millions, where applicable)		
Electric	**$ 16.9**	$ 15.8	$ 18.7
Natural gas distribution	**3.9**	3.6	.7
Utility services	**6.2**	6.4	12.9
Pipeline and energy services	**18.2**	19.1	16.4
Natural gas and oil production	**63.0**	53.2	63.2
Construction materials and mining	**54.4**	48.7	43.2
Independent power production and other	**12.0**	.9	–
Earnings on common stock	**$174.6**	$147.7	$155.1
Earnings per common share – basic	**$ 1.57**	$ 1.39	$ 1.54
Earnings per common share – diluted	**$ 1.55**	$ 1.38	$ 1.52
Return on average common equity	**13.0%**	12.5%	15.3%

2003 compared to 2002 Consolidated earnings for 2003 increased $26.9 million from the comparable prior period. Contributing to the earnings increase were higher earnings at the independent power production and other businesses primarily resulting from the acquisition of the Colorado and California electric generating facilities acquired in late 2002 and early 2003, respectively, and higher income from the Company's share of its equity investment in Brazil. Increased earnings at the natural gas and oil production business were primarily due to higher natural gas and oil prices and natural gas production, offset in part by the absence in 2003 of the 2002 compromise agreement gain of $27.4 million ($16.6 million after tax) which was included in 2002 operating revenues and the $12.7 million ($7.7 million after tax) noncash transition charge in 2003, reflecting the cumulative effect of an accounting change, as discussed in Note 19 and Note 9 of Notes to Consolidated Financial Statements, respectively, and higher depreciation, depletion and amortization expense. Earnings increased at the construction materials and mining business due to higher aggregate volumes and margins and higher ready-mixed concrete volumes at existing operations; partially offset by lower asphalt margins; higher selling, general and administrative costs; and higher depreciation, depletion and amortization expense. Stronger sales for resale volumes and margins and higher retail volumes at the electric business and rate relief approved by various public service commissions at the natural gas distribution business, partially offset by higher operation and maintenance expense at both these businesses, also added to the increase in earnings. In addition, earnings at the natural gas distribution business increased due to the absence in 2003 of an adjustment of $3.3 million (after tax) in 2002 related to certain pipeline capacity charges, partially offset by higher income taxes in 2003, the result of the reversal of certain tax contingency reserves in 2002. Decreased earnings at the pipeline and energy services and utility services businesses slightly offset the earnings increase. Lower workloads and margins at the utility services business are a reflection of the continuing effects of the soft economy and the downturn in the telecommunications market.

2002 compared to 2001 Consolidated earnings for 2002 decreased $7.4 million from the comparable prior period. Lower earnings at the natural gas and oil production business were largely due to lower realized natural gas and oil prices offset in part by the previously mentioned compromise agreement gain and higher natural gas production. Also adding to the decrease in earnings were lower earnings at the utility services business due to decreased margins in the Rocky Mountain and Central regions and the write-off of certain receivables and restructuring of the engineering function, partially offset by increased workloads in the Southwest and Northwest regions. Decreased sales for resale prices partially offset by increased retail sales revenues at the electric business also added to the decrease in earnings. Partially offsetting the earnings decrease were higher earnings at the construction materials and mining business due to earnings from businesses acquired since the comparable prior period, higher aggregate, asphalt and cement sales volumes, and increased construction revenues, partially offset by the 2001 gain 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 2001 other income – net, as discussed in Note 14 of Notes to Consolidated Financial Statements. Also partially offsetting the earnings decrease were higher earnings at the natural gas distribution business due to higher retail sales volumes and lower income taxes, largely the result of the reversal of certain tax contingency reserves, partially offset by an adjustment of $3.3 million (after tax) related to certain pipeline capacity charges. Higher gathering revenues, partially offset by the net effects of the sale of certain smaller nonstrategic properties in 2001 at the pipeline and energy services business, and earnings from the independent power production and other businesses, also slightly offset the earnings decline.

FINANCIAL AND OPERATING DATA

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

ELECTRIC

Years ended December 31,	2003	2002	2001
	(Dollars in millions, where applicable)		
Operating revenues:			
Retail sales	**$148.1**	$142.1	$137.3
Sales for resale and other	**30.5**	20.5	31.5
	178.6	162.6	168.8
Operating expenses:			
Fuel and purchased power	**62.0**	56.0	57.4
Operation and maintenance	**52.9**	46.0	45.6
Depreciation, depletion and amortization	**20.2**	19.6	19.5
Taxes, other than income	**7.7**	7.1	7.6
	142.8	128.7	130.1
Operating income	**$ 35.8**	$ 33.9	$ 38.7
Retail sales (million kWh)	**2,359.9**	2,275.0	2,177.9
Sales for resale (million kWh)	**841.6**	784.6	898.2
Average cost of fuel and purchased power per kWh	**$ .019**	$ .018	$ .018

2003 compared to 2002 Electric earnings increased as a result of 48 percent higher average sales for resale prices and 7 percent higher sales for resale volumes, both due to stronger sales for resale markets. Higher retail sales revenues, due primarily to higher retail sales volumes, largely to residential, commercial and large industrial customers, also added to the increase in earnings. Partially offsetting the earnings increase was higher operation and maintenance expenses, including repair and maintenance at certain electric generating stations, insurance and payroll-related costs. Increased fuel and purchased power costs related to sales for resale also partially offset the earnings increase.

2002 compared to 2001 Electric earnings decreased as a result of lower average realized sales for resale prices, which were 34 percent lower than the prior 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 the prior year. Partially offsetting the earnings decline were increased retail sales volumes, which were 4 percent higher than the prior 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.

NATURAL GAS DISTRIBUTION

Years ended December 31,	2003	2002	2001
	(Dollars in millions, where applicable)		
Operating revenues:			
Sales	**$270.2**	$182.5	$251.3
Transportation and other	**4.4**	4.1	4.1
	274.6	186.6	255.4
Operating expenses:			
Purchased natural gas sold	**211.1**	132.9	200.7
Operation and maintenance	**41.8**	36.5	36.6
Depreciation, depletion and amortization	**10.0**	9.9	9.4
Taxes, other than income	**5.2**	4.9	5.1
	268.1	184.2	251.8
Operating income	**$ 6.5**	$ 2.4	$ 3.6
Volumes (MMdk):			
Sales	**38.6**	39.6	36.5
Transportation	**13.9**	13.7	14.3
Total throughput	**52.5**	53.3	50.8
Degree days (% of normal)*	**97.3%**	101.1%	94.5%
Average cost of natural gas, including transportation thereon, per dk	**$ 5.47**	$ 3.22	$ 5.50

**Degree days are a measure of the daily temperature-related demand for energy for heating.*

2003 compared to 2002 Earnings at the natural gas distribution business increased due to higher retail sales rates, the result of rate relief approved by various public service commissions. Also adding to the increase in earnings was the absence in 2003 of an adjustment of $3.3 million (after tax) in 2002 related to certain pipeline capacity charges. Partially offsetting the earnings increase were higher operation and maintenance expenses, primarily due to higher payroll-related costs, and higher income taxes in 2003, the result of the reversal of certain tax contingency reserves in 2002. Decreased returns on natural gas held in storage and lower retail sales volumes due to weather that was 4 percent warmer than last year, also partially offset the earnings increase. The pass-through of higher natural gas prices is reflected in the increase in both sales revenues and purchased natural gas sold.

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 the prior year, largely the result of weather that was 9 percent colder than the prior period; 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. An 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.

UTILITY SERVICES

Years ended December 31,	2003	2002	2001
	(Dollars in millions)		
Operating revenues	**$434.2**	$458.7	$364.8
Operating expenses:			
Operation and maintenance	**395.9**	419.0	321.0
Depreciation, depletion and amortization	**10.3**	9.9	8.4
Taxes, other than income	**15.1**	15.8	10.2
	421.3	444.7	339.6
Operating income	**$ 12.9**	$ 14.0	$ 25.2

2003 compared to 2002 Utility services earnings decreased slightly as a result of lower line construction workloads and margins in the Southwest and Central regions and lower workloads and margins in the telecommunications industry in the Rocky Mountain region. Increased selling, general and administrative expenses and lower inside electrical workloads and margins in the Central region also contributed to the decrease in earnings. Partially offsetting the earnings decrease were the absence in 2003 of the 2002 write-off of certain receivables and restructuring of the engineering function of approximately $5.2 million (after tax) and higher line construction margins in the Northwest and Rocky Mountain regions. Lower margins are a reflection of the continuing effects of the soft economy in this sector and the downturn in the telecommunications market.

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 expenses resulted largely from businesses acquired since the comparable prior period.

PIPELINE AND ENERGY SERVICES

Years ended December 31,	2003	2002	2001
	(Dollars in millions)		
Operating revenues:			
Pipeline	**$ 97.2**	$ 95.3	$ 87.1
Energy services	**155.0**	69.9	444.0
	252.2	165.2	531.1
Operating expenses:			
Purchased natural gas sold	**149.5**	58.3	433.5
Operation and maintenance	**46.6**	47.3	47.1
Depreciation, depletion and amortization	**15.0**	14.8	14.3
Taxes, other than income	**5.9**	5.7	5.8
	217.0	126.1	500.7
Operating income	**$ 35.2**	$ 39.1	$ 30.4
Transportation volumes (MMdk):			
Montana-Dakota	**34.1**	33.3	34.1
Other	**56.1**	66.6	63.1
	90.2	99.9	97.2
Gathering volumes (MMdk)	**75.9**	72.7	61.1

2003 compared to 2002 Earnings at the pipeline and energy services business decreased as a result of reduced natural gas margins and lower technology services revenues at the energy services businesses. Also contributing to the decrease in earnings were lower transportation volumes, largely resulting from lower volumes transported to storage. Partially offsetting the earnings decrease were increased revenues from higher transportation reservation fees resulting from an increase in the level of firm services provided, higher gathering volumes of 4 percent and lower financing-related costs. The increase in energy services revenues and the related increase in purchased natural gas sold includes the effect of increases in natural gas prices since the comparable prior period.

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 the prior 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 expenses and higher depreciation, depletion and amortization expense, a result of 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.

NATURAL GAS AND OIL PRODUCTION

Years ended December 31,	2003	2002	2001
	(Dollars in millions, where applicable)		
Operating revenues:			
Natural gas	**$213.5**	$131.0	$153.2
Oil	**50.6**	42.1	47.7
Other	**.2**	30.5*	8.9
	264.3	203.6	209.8
Operating expenses:			
Purchased natural gas sold	**.1**	.1	2.8
Operation and maintenance:			
Lease operating costs	**31.6**	27.5	27.8
Gathering and transportation	**14.7**	12.3	5.8
Other	**17.2**	15.8	16.8
Depreciation, depletion and amortization	**61.0**	48.7	41.7
Taxes, other than income:			
Production and property taxes	**21.0**	12.7	10.8
Other	**.4**	.9	.2
	146.0	118.0	105.9
Operating income	**$118.3**	$ 85.6	$103.9
Production:			
Natural gas (MMcf)	**54,727**	48,239	40,591
Oil (000's of barrels)	**1,856**	1,968	2,042
Average realized prices (including hedges):			
Natural gas (per Mcf)	**$ 3.90**	$ 2.72	$ 3.78
Oil (per barrel)	**$27.25**	$22.80	$24.59
Average realized prices (excluding hedges):			
Natural gas (per Mcf)	**$ 4.28**	$ 2.54	$ 3.74
Oil (per barrel)	**$28.42**	$23.26	$23.72
Production costs, including taxes, per net equivalent Mcf:			
Lease operating costs	**$ .48**	$ .46	$ .53
Gathering and transportation	**.22**	.20	.11
Production and property taxes	**.32**	.21	.20
	$ 1.02	$ .87	$ .84

**Includes the effects of a compromise agreement gain of $27.4 million ($16.6 million after tax).*

2003 compared to 2002 Natural gas and oil production earnings increased due to higher realized natural gas prices of 43 percent; higher natural gas production of 13 percent, primarily from enhanced natural gas production from operated properties located in the Rocky Mountain area; and higher average realized oil prices of 20 percent. Partially offsetting the earnings increase were the 2002 compromise agreement gain and the noncash transition charge in 2003, reflecting the cumulative effect of an accounting change, both as previously discussed. Also partially offsetting the earnings increase were increased depreciation, depletion and amortization expense due to higher natural gas production volumes and higher rates. The higher depreciation, depletion and amortization rates are attributable to increased costs of reserve additions and the effects of the adoption of Statement of Financial Accounting Standards (SFAS) No. 143, "Accounting for Asset Retirement Obligations." Higher lease operating expenses due in part to increased production, higher general and administrative costs, decreased oil production of 6 percent and higher interest expense also partially offset the earnings increase.

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 the prior 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 expenses, 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 previously discussed 2002 compromise agreement gain.

CONSTRUCTION MATERIALS AND MINING

Years ended December 31,	2003	2002	2001
	(Dollars in millions)		
Operating revenues:			
Construction materials	**$1,104.4**	$962.3	$794.6
Coal	**–***	–*	12.3*
	1,104.4	962.3	806.9
Operating expenses:			
Operation and maintenance	**924.2**	797.7	673.1
Depreciation, depletion and amortization	**63.6**	54.4	46.6
Taxes, other than income	**25.0**	18.8	15.7
	1,012.8	870.9	735.4
Operating income	**$ 91.6**	$ 91.4	$ 71.5
Sales (000's):			
Aggregates (tons)	**38,438**	35,078	27,565
Asphalt (tons)	**7,275**	7,272	6,228
Ready-mixed concrete (cubic yards)	**3,484**	2,902	2,542
Coal (tons)	**–***	–*	1,171*

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

2003 compared to 2002 Construction materials and mining earnings increased due to higher aggregate and ready-mixed concrete volumes and margins and higher construction activity, all at existing operations. Earnings from companies acquired since the comparable period last year also added to the earnings increase. Partially offsetting the increase in earnings were higher selling, general and administrative costs, including insurance, computer system support and payroll-related costs; higher depreciation, depletion and amortization expense primarily due to higher property, plant and equipment balances; and higher aggregate volumes produced. Lower asphalt margins from existing operations, due in part to higher asphalt oil costs, also partially offset the earnings increase.

2002 compared to 2001 Earnings for the construction materials and mining business increased as a result of earnings from businesses acquired since the comparable prior period; 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 2001 gain from the sale of the Company's coal operations, as previously discussed, 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.

INDEPENDENT POWER PRODUCTION AND OTHER

Years ended December 31,	2003	2002	2001
	(Dollars in millions)		
Operating revenues	**$35.0**	$6.8	$–
Operating expenses:			
Operation and maintenance	**15.0**	6.4	–
Depreciation, depletion and amortization	**8.2**	.7	–
	23.2	7.1	–
Operating income (loss)*	**$11.8**	$ (.3)	$–
Net generation capacity – kW**	**279,600**	213,000	–
Electricity produced and sold (thousand kWh)**	**270,044**	15,804	–

**Reflects international operations for 2003 and 2002 and domestic operations acquired on November 1, 2002 and January 31, 2003.*

***Reflects domestic independent power production operations.*

NOTE: The earnings from the Company's equity method investment in Brazil were included in other income – net and, thus, are not reflected in the above table.

2003 compared to 2002 Earnings for the independent power production and other businesses increased largely from the domestic businesses acquired in late 2002 and early 2003, partially offset by higher interest expense, resulting from higher average debt balances relating to these acquisitions. Also adding to the earnings increase was higher net income of $3.7 million from the Company's share of its equity investment in Brazil due primarily to higher margins from higher capacity revenues, which resulted from all four units being in operation in 2003 compared to only two operational units in 2002 (effective July 2002), as well as from foreign currency gains from the revaluation of the Brazilian real, partially offset by the mark-to-market loss on an embedded derivative in the electric power contract and higher interest expense due to a full year of debt in 2003.

2002 compared to 2001 Earnings at the independent power production and other businesses 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 intersegment transactions. The amounts relating to the elimination of intersegment transactions are as follows:

Years ended December 31,	2003	2002	2001
		(In millions)	
Operating revenues	**$191.1**	$114.3	$113.2
Purchased natural gas sold	**176.5**	98.8	107.7
Operation and maintenance	**14.6**	15.5	5.5

For further information on intersegment eliminations, see Note 14 of Notes to Consolidated Financial Statements.

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 these 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. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the 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 the 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 the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any 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.

Economic Risks

The Company's natural gas and oil production business is dependent on factors, including commodity prices, which 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 current soft economic environment and the depressed telecommunications market may have a general negative impact on the Company's future revenues and may result in a goodwill impairment for Innovatum, Inc. (Innovatum), an indirect wholly owned subsidiary of the Company.

In response to the ongoing war against terrorism by the United States and the bankruptcy of several large energy and telecommunications companies and other large enterprises, the financial markets have been volatile. A soft economy could negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, would negatively affect the demand for the Company's products and services.

Innovatum, which specializes in cable and pipeline magnetization and locating, is subject to the economic conditions within the telecommunications and energy industries. Innovatum has also developed a hand-held locating device that can detect both magnetic and plastic materials. Innovatum could face a future goodwill impairment if there is a continued downturn in the telecommunications and energy industries or if it cannot find a successful market for the hand-held locating device. At December 31, 2003, 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 success of the hand-held locating device at Innovatum, rapid changes in technology, competitors and potential new customers.

The Company relies on financing sources and capital markets. If the Company were unable to access financing in the future, the Company's ability to execute its business plans, make capital expenditures or pursue acquisitions that the Company may otherwise rely on for future growth could be impaired.

The Company relies on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from 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 the Company's 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 prolonged economic downturn
- The bankruptcy of unrelated industry leaders in the same line of business
- Capital market conditions generally
- Volatility in commodity prices
- Terrorist attacks
- Global events

Environmental and Regulatory Risks

Some of the Company's operations are subject to extensive environmental laws and regulations that may increase its costs of operations, impact or limit its business plans, or expose the Company to environmental liabilities. One of the Company's subsidiaries is subject to litigation in connection with its coalbed natural gas development activities.

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. Public officials and entities, as well as private individuals and organizations, 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.

Existing environmental regulations may be revised and new regulations seeking to protect the environment may 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, and/or certain of its operations are the subject of, 11 lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material effect on Fidelity's existing coalbed natural gas operations and/or the 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, and 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 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.

Risks Relating to 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, off-take, transmission or other material agreements, as well as the risk of performance below expected levels of output or efficiency.

The Company has begun construction of a 113-megawatt coal-fired development project in Hardin, Montana. Based on demand and power pricing in the Northwest, the plant is being built on a merchant basis. Unanticipated events could delay completion of construction, start-up and/or operation of the project. Changes in the market price for power from the Company's projections could also negatively impact earnings to be derived from the project.

Risks Relating to Foreign Operations

The value of the Company's investment in foreign operations may diminish due to political, regulatory and economic conditions and changes in currency exchange rates in countries where the Company does business.

The Company is subject to political, regulatory and economic conditions and changes in currency exchange 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 220-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.

Other Risks

Competition is increasing in all of the Company's businesses.

All of the Company's businesses are subject to increased competition. The independent power industry includes numerous strong and capable competitors, many of which have greater resources and more 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 as well as in the sale of its production output.

Weather conditions can adversely affect the Company's operations and revenues.

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 wind-powered operation at the independent power production business, affect the price of energy commodities, affect the ability to perform services at the utility services and construction materials and mining businesses and affect ongoing operation and maintenance activities for the pipeline and energy services and natural gas and oil production businesses. In addition, severe weather can be destructive, causing outages and/or property damage, which could require additional costs to be incurred. As a result, adverse weather conditions could negatively affect the Company's results of operations and financial condition.

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 businesses. 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 is 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, and other factors that are listed in Part I in the Company's 2003 Form 10-K. 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.

- Earnings per common share for 2004, diluted, are projected in the range of $1.55 to $1.68.
- The Company expects the percentage of 2004 earnings per common share, diluted, by quarter to be in the following approximate ranges:
  - First quarter – 13 percent to 18 percent
  - Second quarter – 19 percent to 24 percent
  - Third quarter – 35 percent to 40 percent
  - Fourth quarter – 23 percent to 28 percent
- 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.
- The Company will consider issuing equity from time to time to keep debt at the nonregulated businesses at no more than 40 percent of total capitalization.
- The Company has formed an alliance with several electric cooperatives in the region to evaluate potential utility opportunities presented by the bankruptcy of NorthWestern Corporation. NorthWestern filed for Chapter 11 bankruptcy protection on September 14, 2003.

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.

- Expected returns in 2004 are anticipated to be generally consistent with authorized levels.

- Montana-Dakota filed an application with the North Dakota Public Service Commission (NDPSC) seeking an increase in electric retail rates of $7.8 million annually or 9.1 percent above current rates. On December 18, 2003, the NDPSC approved a Settlement Agreement for an increase of $1.0 million annually and a sharing mechanism between Montana-Dakota and retail customers of wholesale electric sales margins. For further information on the electric rate increase application, see Note 18 of Notes to Consolidated Financial Statements.

- Regulatory approval has been received from the NDPSC and the South Dakota Public Utilities Commission (SDPUC) on the Company's plans to purchase energy from a 20-megawatt wind energy farm in North Dakota. The contract provides for this wind energy farm to be on-line by early to mid 2004.

- The Company continues to evaluate potential needs for future generation. The Company expects to build or acquire an additional 175-megawatts to 200-megawatts of capacity over the next 10 years to replace expiring contracts and meet system growth requirements. The Company is working with the state of North Dakota to determine the feasibility of constructing a lignite-fired power plant in western North Dakota. The Company also announced its involvement in a coalition with four other utilities to study the feasibility of building a coal-based electric generating facility possibly combined with a wind energy facility at potential sites in North Dakota, South Dakota and Iowa. The costs of building and/or acquiring the additional generating capacity needed by the utility are expected to be recovered in rates.

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 2004 is expected to be approximately 52 million decatherms.

- The Company expects to seek natural gas rate increases from time to time to offset higher expected operating costs.

- Montana-Dakota filed an application with the SDPUC seeking an increase in natural gas retail rates of $2.2 million annually or 5.8 percent above current rates. On December 2, 2003, the SDPUC approved a Settlement Stipulation for an increase of $1.3 million annually. Great Plains filed an application with the Minnesota Public Utilities Commission (MPUC) seeking an increase in natural gas retail rates of $1.6 million annually or 6.9 percent above current rates. On October 9, 2003, the MPUC issued a Final Order authorizing an increase of $1.1 million annually. For further information on the natural gas rate increase applications, see Note 18 of Notes to Consolidated Financial Statements.

Utility services

- Revenues for this segment are expected to be in the range of $440 million to $490 million in 2004.

- This segment anticipates margins to increase in 2004 as compared to 2003 levels.

Pipeline and energy services

- In 2004, total natural gas throughput is expected to increase approximately 25 percent to 30 percent over 2003 levels largely due to the 253-mile Grasslands Pipeline, which began providing natural gas transmission service on December 23, 2003.

- Firm capacity for the Grasslands Pipeline is currently 90 million cubic feet per day with expansion possible to 200 million cubic feet per day.

- Transportation rates are expected to decline in 2004 from 2003 levels due to the estimated effects of a FERC rate order received in July 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. Innovatum recently developed a hand-held locating device that can detect both magnetic and plastic materials. One of the possible uses for this product would be in the detection of unexploded ordnance. Innovatum is in the preliminary stages of working with and demonstrating the device to a Department of Defense contractor and has met with individuals from the Department of Defense.

Natural gas and oil production

- In 2004, this segment expects a combined production increase of approximately 10 percent over 2003 levels. Currently, this segment's gross operated natural gas production is approximately 140,000 Mcf to 150,000 Mcf per day.
- This segment continues to expand its operated production. Natural gas production from operated properties was 74 percent and 69 percent of total natural gas production for the years ended December 31, 2003 and 2002, respectively.
- This segment expects to participate in drilling more than 400 wells in 2004.
- At December 31, 2003, this segment had 118 gross wells in the process of drilling or under evaluation, 113 of which were development wells and five of which were exploratory wells. This segment expects to complete drilling and testing the majority of these wells within the next 12 months.
- Natural gas prices in the Rocky Mountain region for February through December 2004 reflected in the Company's 2004 earnings guidance are in the range of $3.25 to $3.75 per Mcf. The Company's estimates for natural gas prices on the NYMEX for February through December 2004, reflected in the Company's 2004 earnings guidance, are in the range of $4.00 to $4.50 per Mcf. During 2003, more than two-thirds 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 2004, reflected in the Company's 2004 earnings guidance, are in the range of $26 to $30 per barrel.
- The Company has hedged a portion of its 2004 estimated annual natural gas production. The Company has entered into agreements representing approximately 30 percent to 35 percent of 2004 estimated annual natural gas production. The agreements are at various indices and range from a low CIG index of $3.75 to a high CIG index of $5.48 per Mcf.
- The Company has hedged a portion of its 2004 oil production. The Company has entered into agreements at NYMEX prices with a low of $28.84 and a high of $30.28, representing approximately 30 percent to 35 percent of 2004 estimated annual oil production.
- The Company has hedged less than 5 percent of its 2005 estimated annual natural gas production and will continue to evaluate additional opportunities.

Construction materials and mining

- Aggregate volumes in 2004 are expected to be comparable to 2003 levels, while ready-mixed concrete and asphalt volumes are expected to increase over 2003 levels.
- Revenues in 2004 are expected to increase by approximately 5 percent to 10 percent over 2003 levels.
- Knife River expects that the replacement funding legislation for the Transportation Equity Act for the 21st Century (TEA-21) will be at funding levels equal to or higher than the funding under TEA-21.
- On February 6, 2004, this segment acquired a ready-mixed concrete producer and concrete and asphalt paving company in Iowa and two aggregate mining and production companies in Minnesota. The companies have combined annual revenues of approximately $90 million.

Independent power production and other

- Earnings projections in 2004 for independent power production and other operations include the estimated results from the wind-powered electric generating facility in California, the natural gas-fired electric generating facility in Colorado, and the Company's 49-percent ownership in a 220-megawatt natural gas-fired electric generating facility in Brazil. Earnings are expected to be in the range of $18 million to $23 million in 2004.
- The Company has begun construction of a 113-megawatt coal-fired development project in Hardin, Montana, as previously discussed in Risk Factors and Cautionary Statements that May Affect Future Results. Based on demand and power pricing in the Northwest, the plant is being built on a merchant basis. Efforts will continue towards securing a contract for the off-take of the plant. The Company is optimistic that this plant will be under contract by the time of plant completion. The projected on-line date for this plant is late 2005.

NEW ACCOUNTING STANDARDS

In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. Compensation expense recognized for awards granted on or after January 1, 2003, for the year ended December 31, 2003, was $41,000 (after tax).

In June 2001, the Financial Accounting Standards Board (FASB) approved SFAS No. 143. Upon adoption of SFAS No. 143, the Company recorded an additional discounted liability of $22.5 million and a regulatory asset of $493,000, increased net property, plant and equipment by $9.6 million and recognized a one-time cumulative effect charge of $7.6 million (net of deferred income tax benefits of $4.8 million).

In April 2002, the FASB approved SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections." The adoption of SFAS No. 145 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" (FIN 45). The Company is applying the initial recognition and initial measurement provisions of FIN 45 to guarantees issued or modified after December 31, 2002.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 did not have a material effect on the Company's financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Company will apply SFAS No. 150 to any financial instruments entered into or modified after May 31, 2003. Beginning in 2003, the Company reported its preferred stock subject to mandatory redemption as a liability in accordance with SFAS No. 150. The transition to SFAS No. 150 did not have a material effect on the Company's financial position or results of operations.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised 2003), "Consolidation of Variable Interest Entities" (FIN 46 (revised)), which revised FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 (revised) shall be applied to all entities subject to FIN 46 (revised) no later than the end of the first reporting period that ends after March 15, 2004. However, an entity that applied FIN 46 to an entity prior to the effective date of FIN 46 (revised) shall either continue to apply FIN 46 until the effective date of FIN 46 (revised) or apply FIN 46 (revised) at an earlier date. The adoption of FIN 46 did not have a material effect on the Company's financial position or results of operations. The Company will continue to apply FIN 46 until the effective date of FIN 46 (revised).

In December 2003, the FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pension and Other Postretirement Benefits." SFAS No. 132 (revised 2003) is effective for financial statements with fiscal years ending after December 15, 2003. The Company applied SFAS No. 132 (revised 2003) to its consolidated financial statements issued after December 15, 2003.

In January 2004, the FASB issued FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FASB Staff Position No. FAS 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (2003 Medicare Act). The Company provides prescription drug benefits to certain eligible employees and has elected the one-time deferral of accounting for the effects of the 2003 Medicare Act. The Company intends to analyze the 2003 Medicare Act, along with the authoritative guidance, when issued, to determine if its benefit plans need to be amended and how to record the effects of the 2003 Medicare Act.

For further information on SFAS No. 123, SFAS No. 143, SFAS No. 145, FIN 45, SFAS No. 149, SFAS No. 150, FIN 46 (revised), SFAS No. 132 (revised 2003) and FASB Staff Position No. FAS 106-1, see Note 1 of Notes to Consolidated Financial Statements.

CRITICAL ACCOUNTING POLICIES INVOLVING SIGNIFICANT ESTIMATES

The Company has prepared its financial statements in conformity with accounting principles generally accepted in the United States of America. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. The Company's significant accounting policies are discussed in Note 1 of Notes to Consolidated Financial Statements.

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; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments, including 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. The Company's critical accounting policies are subject to judgments and uncertainties that 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.

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. The following critical accounting policies involve significant judgments and estimates.

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 SFAS No. 142, "Goodwill and Other Intangible Assets." 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. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing the carrying value to its fair value, based on an estimate of undiscounted future cash flows attributable to the assets. In the case of goodwill, the first step, used to identify a potential impairment, compares the fair value of the reporting unit using discounted cash flows, with its carrying amount, including goodwill. The second step, used to measure the amount of the impairment loss if step one indicates a potential impairment, compares the implied fair value of the reporting unit goodwill with the carrying amount of goodwill.

Fair value is the amount at which the asset could be bought or sold in a current transaction between willing parties. The Company uses critical estimates and assumptions when testing assets for impairment, including present value techniques based on estimates of cash flows, quoted market prices or valuations by third parties, 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.

There is risk involved when determining the fair value of assets, tangible and intangible, as there may be unforeseen events and changes in circumstances and market conditions and changes in estimates of future cash flows.

The Company believes its estimates used in calculating the fair value of long-lived assets, including goodwill and identifiable intangibles, are reasonable based on the information that is known at the point in time the estimates are made. In addition, goodwill impairment testing is performed annually in accordance with SFAS No. 142 and no impairment loss has been recorded subsequent to the adoption of SFAS No. 141, "Business Combinations" and SFAS No. 142.

Natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities. 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. Judgments and assumptions are made when estimating and valuing reserves. There is risk that 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.

Estimates of reserves are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing all available engineering and geologic data derived from well tests. Other factors used in the reserve estimates are current natural gas and oil prices, current estimates of well operating and future development costs, and the interest owned by the Company in the well. These estimates are refined as new information becomes available.

Historically, the Company has not had any material revisions to its reserve estimates. As a result, the Company has not changed its practice in estimating reserves and does not anticipate changing its methodologies in the future.

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 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. Critical estimates related to the recognition of revenue include the accumulated provision for revenues subject to refund and costs on construction contracts under the percentage-of-completion method.

Estimates for revenues subject to refund are established initially for each regulatory rate proceeding and are subject to change depending on the applicable regulatory agency's (Agency) approval of final rates. These estimates are based on the Company's analysis of its as-filed application compared to previous Agency decisions in prior rate filings by the Company and other regulated companies. The Company periodically reviews the status of its outstanding regulatory proceedings and reserve assumptions and may from time to time change its reserve estimates subject to known developments as the regulatory proceedings move through the regulatory review process. The accuracy of the estimates is ultimately determined when the Agency issues its final ruling on each regulatory proceeding for which revenues were subject to refund. Estimates have changed from time to time as additional information has become available as to what the ultimate outcome may be and will likely continue to change in the future as new information becomes available on each outstanding regulatory proceeding that is subject to refund.

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. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. There are risks involved when making these estimates as contract prices are generally set before the work is performed, which means every project could contain significant unknown risks such as volatile labor and material costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners.

Several factors are evaluated in determining the bid price for contract work. These include, but are not limited to, the complexities of the job, past history performing similar types of work, seasonal weather patterns, competition and market conditions, job site conditions, work force safety, reputation of the project owner, availability of labor and materials, project location and project completion dates. As a project commences, estimates are continually monitored and revised as information becomes available and actual costs and conditions surrounding the job become known.

The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known at the point in time the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job.

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 excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. 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.

Acquired assets and liabilities assumed by the Company that are subject to critical estimates include property, plant and equipment (including owned aggregate reserve deposits) and intangible assets.

The fair value of owned recoverable aggregate reserve deposits are determined using qualified internal personnel as well as geologists. Reserve estimates are calculated based on the best available data. This data is collected from drill holes and other subsurface investigations as well as investigations of surface features such as mine highwalls and other exposures of the aggregate reserves. Mine plans, production history and geologic data are also used to estimate reserve quantities. Value is assigned to the aggregate reserves based on a review of market royalty rates, expected cash flows and the number of years of recoverable aggregate reserves at owned aggregate sites.

The fair value of property, plant and equipment is based on a valuation performed either by qualified internal personnel and/or outside appraisers. Fair values assigned to plant and equipment are based on several factors including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase.

Intangible assets are identified and valued using the guidelines of SFAS No. 141. The fair value of intangible assets is based on estimates including royalty rates, lease terms and other discernible factors for acquired leasehold rights, and estimated cash flows.

While the allocation of the purchase price of an acquisition is subject to a high level of judgment and uncertainty, the Company does not expect the estimates to vary significantly once an acquisition has been completed. The Company believes its estimates have been reasonable in the past as there have been no significant valuation adjustments subsequent to the final allocation of the purchase price to the acquired assets and liabilities. In addition, goodwill impairment testing is performed annually in accordance with SFAS No. 142. No impairment loss has been recorded subsequent to the adoption of SFAS No. 141 and SFAS No. 142, as previously discussed.

Asset retirement obligations

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. The Company has recorded obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties and certain other obligations associated with leased properties.

The liability for future asset retirement obligations bears the risk of change as many factors go into the development of the estimate of these obligations and the possibility that over time these factors can and will change. Factors used in the estimation of future asset retirement obligations include estimates of current retirement costs, future inflation factors, life of the asset and discount rates. These factors determine both a present value of the retirement liability and the accretion to the retirement liability in subsequent years.

Long-lived assets are reviewed to determine if a legal retirement obligation exists. If a legal retirement obligation exists, a determination of the liability is made if a reasonable estimate of the present value of the obligation can be made. The present value of the retirement obligation is calculated by inflating current estimated retirement costs of the long-lived asset over its expected life to determine the expected future cost and then discounting the expected future cost back to the present value using a discount rate equal to the credit-adjusted risk-free interest rate in effect when the liability was initially recognized.

These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will change as the estimated useful lives of the assets change, the current estimated retirement costs change, new legal retirement obligations occur and/or as existing legal asset retirement obligations, for which a reasonable estimate of fair value could not initially be made because of uncertainty, become less uncertain and a reasonable estimate of the future liability can be made.

Pension and other postretirement benefits

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to these plans. Costs of providing pension and other postretirement benefits bear the risk of change, as they are dependent upon numerous factors based on assumptions of future conditions.

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases and healthcare cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers both current market conditions and expected future market trends, including changes in interest rates and equity and bond market performance. Another key variable in determining benefit expense or income is the discount rate. In selecting the discount rate, the Company uses the yield of a fixed-income debt security, which has a rating of "Aa" or higher published by a recognized rating agency, as well as other factors, as a basis. The pension and other postretirement benefit plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and bond market returns as well as changes in general interest rates may result in increased or decreased pension and other postretirement benefit costs in the future. Management estimates the rate of compensation increase based on long-term assumed wage increases and the healthcare cost trend rates are determined by historical and future trends.

The Company believes the estimates made for its pension and other postretirement benefits are reasonable based on the information that is known at the point in time the estimates are made. These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will be affected by changes in the discount rate, the expected long-term return on plan assets, the rate of compensation increase and healthcare cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs.

LIQUIDITY AND CAPITAL COMMITMENTS

Cash flows

Operating activities Cash flows provided by operating activities in 2003 increased $92.1 million compared to 2002, primarily the result of higher deferred income taxes of $33.8 million due in part to additional tax depreciation allowed in 2003. Also adding to the increase in cash flows provided by operating activities were higher depreciation, depletion and amortization expense of $30.4 million, resulting largely from increased property, plant and equipment balances and higher mineral production volumes, and an increase in cash from net income of $26.9 million.

In 2002, cash flows from operating activities decreased $22.2 million compared to 2001, largely the result of a decrease in cash from working capital items of $58.4 million. The working capital decrease was primarily due to lower natural gas prices compared to 2001. 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.

Investing activities Cash flows used in investing activities in 2003 increased $67.1 million compared to 2002, 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 $78.1 million, partially offset by an increase in cash flows from investments of $7.2 million and proceeds from notes receivable of $3.8 million. Net capital expenditures exclude the noncash transactions related to acquisitions, including the issuance of the Company's equity securities. The noncash transactions were $42.4 million and $47.2 million for the years ended December 31, 2003 and 2002, respectively.

In 2002, cash flows used in investing activities increased $6.2 million compared to 2001, the result of an increase in net capital expenditures 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.

Financing activities Cash flows provided by financing activities in 2003 decreased $31.9 million compared to 2002, the result of a decrease of proceeds from issuance of common stock of $54.6 million, a net decrease in short-term borrowings of $40.0 million and an increase in the repayment of long-term debt of $23.2 million. The increase in the issuance of long-term debt of $90.8 million partially offset the decrease in cash provided by financing activities.

In 2002, cash flows provided by financing activities increased $48.8 million compared to 2001. This increase was 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.

Defined benefit pension plans

The Company has qualified noncontributory defined benefit pension plans (Pension Plans) for certain employees. Plan assets consist of investments in equity and fixed income securities. 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. At December 31, 2003, certain Pension Plans' accumulated benefit obligations exceeded these plans' assets by approximately $4.3 million. Pretax pension expense (income) reflected in the years ended December 31, 2003, 2002 and 2001 was $153,000, ($2.4) million and ($4.4) million, respectively. The Company's pension expense is currently projected to be approximately $4.0 million to $5.0 million in 2004. A reduction in the Company's assumed discount rate for Pension Plans along with declines in the equity markets experienced in 2002 and 2001 have combined to largely produce the increase in these costs. Funding for the Pension Plans is actuarially determined. The minimum required contributions for 2003, 2002 and 2001 were approximately $1.6 million, $1.2 million and $442,000, respectively. For further information on the Company's Pension Plans, see Note 16 of Notes to Consolidated Financial Statements.

Capital expenditures

The Company's capital expenditures for 2001 through 2003 and as anticipated for 2004 through 2006 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2001	2002	2003	2004	2005	2006
			(In millions)			
Capital expenditures:						
Electric	$ 14.4	$ 27.8	$ 28.5	$ 23.3	$ 46.3	$123.0
Natural gas distribution	14.7	11.0	15.7	13.5	16.8	16.2
Utility services	70.2	17.3	7.8	9.5	10.3	10.9
Pipeline and energy services	51.0	21.5	93.0	38.3	29.7	32.8
Natural gas and oil production	118.7	136.4	101.7	139.9	138.7	123.2
Construction materials and mining	170.6	106.9	128.5	90.0	82.4	80.7
Independent power production and other	–	95.7	112.8	66.1	80.9	50.7
	439.6	416.6	488.0	380.6	405.1	437.5
Net proceeds from sale or disposition of property	(51.6)	(16.2)	(14.4)	(10.7)	(3.0)	(1.6)
Net capital expenditures	388.0	400.4	473.6	369.9	402.1	435.9
Retirement of long-term debt	115.2	82.6	105.7	27.6	70.9	173.2
	$503.2	$483.0	$579.3	$397.5	$473.0	$609.1

** The estimated 2004 through 2006 capital expenditures reflected in the above table include potential future acquisitions. The Company continues to evaluate potential future acquisitions; however, these acquisitions are dependent upon the availability of economic opportunities and, as a result, actual acquisitions and capital expenditures may vary significantly from the above estimates.*

Capital expenditures for 2003, 2002 and 2001, related to acquisitions, in the preceding table include the following noncash transactions: issuance of the Company's equity securities of $42.4 million in 2003, $47.2 million in 2002 and $57.4 million in 2001.

In 2003, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Montana, North Dakota and Texas and a wind-powered electric generating facility in California. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired in 2002, including the Company's common stock and cash, was $175.0 million. 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.

The 2003 capital expenditures, including those for the previously mentioned acquisitions and retirements of long-term debt, were met from internal sources, the issuance of long-term debt and the Company's equity securities. Estimated capital expenditures for the years 2004 through 2006 include those for:

- Potential future acquisitions
- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Land and building improvements
- Pipeline and gathering expansion projects
- The further enhancement of natural gas and oil production and reserve growth
- Power generation opportunities, including the construction or acquisition of an additional 175-megawatts to 200-megawatts of capacity over the next 10 years and certain construction costs for a 113-megawatt coal-fired development project, as previously discussed
- 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 for the years 2004 through 2006 will be met from various sources. These sources include internally generated funds; commercial paper credit facilities at Centennial Energy Holdings, Inc. (Centennial), a direct 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, 2003.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling $90 million at December 31, 2003. There were no amounts outstanding under the credit agreement at December 31, 2003. The credit agreement supports the Company's $75 million commercial paper program. Under the Company's commercial paper program, $40.0 million was outstanding at December 31, 2003. The commercial paper borrowings are classified as long-term debt as the Company intends to refinance these borrowings on a long-term basis through continued commercial paper borrowings and as further supported by the credit agreement, which expires on July 18, 2006.

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 ratings, 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.

To the extent the Company needs to borrow under its credit agreement, it would be expected to incur increased annualized interest expense on its variable rate debt of approximately $60,000 (after tax) based on December 31, 2003, variable rate borrowings. Based on the Company's overall interest rate exposure at December 31, 2003, this change would not have a material effect on the Company's results of operations or cash flows.

Prior to the maturity of the credit agreement, the Company plans to negotiate the extension or replacement of this agreement that provides credit support to access the capital markets. In the event the Company was unable to successfully negotiate the credit agreement, or in the event the fees on this facility 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, 2003. 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.

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

On December 23, 2003, the Company issued $30 million in aggregate principal amount of its 5.98% Senior Notes due 2033 (Senior Notes). The Senior Notes were issued as a series of debt securities under an Indenture, dated as of December 15, 2003, between the Company and The Bank of New York, as trustee (Indenture Trustee). The Senior Notes are secured by the lien of a matching aggregate principal amount of the Company's First Mortgage Bonds that were issued to the Indenture Trustee for the benefit of the holders of the Senior Notes and a junior lien on the Company's electric and natural gas utility property. The liens securing the Senior Notes may be released in certain circumstances.

On February 10, 2004, the Company issued 2.3 million shares of its common stock and appurtenant preference share purchase rights to the public at a price per share of $23.32 in an underwritten public offering and received net proceeds from the offering of approximately $51.5 million, after deducting underwriting discounts and commissions and offering expenses payable by the Company. Approximately $24 million of the net proceeds was used to repay outstanding indebtedness. The remainder of the net proceeds of the sale of these shares was added to the Company's general funds and may be used for the repayment of outstanding debt obligations, for corporate development purposes (including the acquisition of other businesses and/or business assets), and for other general corporate purposes.

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, 2003, the Company could have issued approximately $313 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 4.7 times and 4.8 times for the years ended December 31, 2003 and 2002, respectively. Additionally, the Company's first mortgage bond interest coverage was 7.4 times and 7.7 times for the years ended December 31, 2003 and 2002, respectively. Common stockholders' equity as a percent of total capitalization was 60 percent at December 31, 2003 and 2002.

Centennial Energy Holdings, Inc. Centennial has two revolving credit agreements with various banks that supports $275 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2003. Under the Centennial commercial paper program, $32.5 million was outstanding at December 31, 2003. The Centennial commercial paper borrowings are classified as long-term debt 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 agreements. The Centennial credit agreements are for $137.5 million each. One of these agreements expires on September 3, 2004, and allows for subsequent borrowings up to a term of one year. The other agreement expires on September 5, 2006. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities.

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, $384.0 million was outstanding at December 31, 2003. To meet potential future financing needs, Centennial may 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 ratings, 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 $49,000 (after tax) based on December 31, 2003, variable rate borrowings. Based on Centennial's overall interest rate exposure at December 31, 2003, this change would not have a material effect on the Company's results of operations or cash flows.

Prior to the maturity of the Centennial credit agreements, Centennial plans to negotiate the extension or replacement of these agreements that provide credit support to access the capital markets. In the event Centennial was unable to successfully negotiate these agreements, or in the event the fees on such facilities 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 agreements 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, 2003. 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.

Certain of Centennial's financing agreements 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 applicable agreements will be in default. Certain of Centennial's financing agreements 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, $55.0 million was outstanding at December 31, 2003.

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, 2003. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

Off balance sheet arrangements

Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX Participacoes Ltda. (MPX) in connection with the Company's equity method investment in the natural gas-fired electric generating facility in Brazil, as discussed in Note 2 of Notes to Consolidated Financial Statements. The Company, through MDU Brasil, owns 49 percent of MPX. The main business purpose of Centennial extending the guarantee to MPX's creditors is to enable MPX to obtain lower borrowing costs. At December 31, 2003, the aggregate amount of borrowings outstanding subject to these guarantees was $45.5 million and the scheduled repayment of these borrowings is $11.0 million in 2004, $10.7 million in 2005, $10.7 million in 2006, $10.7 million in 2007 and $2.4 million in 2008. The individual investor (who through EBX Empreendimentos Ltda. (EBX), a Brazilian company, owns 51 percent of MPX) has also guaranteed a portion of these loans. In the event MPX defaults under its obligation, Centennial and the individual investor would be required to make payments under their guarantees. Centennial and the individual investor have entered into reimbursement agreements under which they have agreed to reimburse each other to the extent they may be required to make any guarantee payments in excess of their proportionate ownership share in MPX. These guarantees are not reflected on the Consolidated Balance Sheets.

As of December 31, 2003, Centennial was contingently liable for the performance of certain of its subsidiaries under approximately $360 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. The purpose of Centennial's indemnification is to allow the subsidiaries to obtain bonding at competitive rates. In the event a subsidiary of the Company does not fulfill its obligations in relation to its bonded contract or obligation, Centennial may be required to make payments under its indemnification. A large portion of these contingent commitments are expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. The surety bonds were not reflected on the Consolidated Balance Sheets.

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 19 of Notes to Consolidated Financial Statements. At December 31, 2003, the Company's commitments under these obligations were as follows:

	2004	2005	2006	2007	2008	Thereafter	Total
				(In millions)			
Long-term debt	$ 27.6	$ 70.9	$173.2	$105.8	$160.2	$429.4	$ 967.1
Operating leases	18.1	12.4	8.7	5.1	3.9	22.1	70.3
Purchase commitments	167.2	67.2	50.1	31.0	30.9	146.3	492.7
	$212.9	$150.5	$232.0	$141.9	$195.0	$597.8	$1,530.1

EFFECTS OF INFLATION

Inflation did not have a significant effect on the Company's operations in 2003, 2002 or 2001.

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 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.

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 an indirect wholly owned subsidiary of the Company, as of December 31, 2003. These agreements call for the subsidiary of the Company 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 2004	$5.17	11,890	$(1,645)
	Weighted Average Floor/Ceiling Price (Per MMBtu)	Notional Amount (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2004	$4.34/$4.94	6,771	$(3,481)
	Weighted Average Fixed Price (Per barrel)	Notional Amount (In barrels)	Fair Value
Oil swap agreements maturing in 2004	$29.25	366	$ (341)

The following table summarizes hedge agreements entered into by the 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)

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.

The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2003. Weighted average variable rates are based on forward rates as of December 31, 2003.

	2004	2005	2006	2007	2008	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$27.6	$70.9	$100.7	$105.8	$160.2	$429.4	$894.6	$941.5
Weighted average interest rate	5.8%	8.0%	6.5%	8.2%	4.4%	6.4%	6.4%	–
Variable rate	–	–	$ 72.5	–	–	–	$ 72.5	$ 71.0
Weighted average interest rate	–	–	1.1%	–	–	–	1.1%	–

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

MDU Brasil has a 49 percent equity investment in a 220-megawatt natural gas-fired electric generating facility (Brazil Generating Facility) in Brazil, which has a portion of its borrowings and payables denominated in U.S. dollars. MDU Brasil 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 Brazil Generating Facility is the Brazilian real. For further information on this investment, see Note 2 of Notes to Consolidated Financial Statements.

MDU Brasil'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 Brazil Generating Facility's U.S. dollar denominated obligations, excluding a U.S. dollar denominated loan from Centennial Energy Resources International Inc (Centennial International), an indirect wholly owned subsidiary of the Company, as discussed below. At December 31, 2003, these U.S. dollar denominated obligations approximated $66.9 million. If, for example, the value of the Brazilian real decreased in relation to the U.S. dollar by 10 percent, MDU Brasil, with respect to its interest in the Brazil Generating Facility, would record a foreign currency transaction loss in net income of approximately $3.0 million (after tax) based on the above U.S. dollar denominated obligations at December 31, 2003. The Brazil Generating Facility also had approximately US$9.5 million of Brazilian real denominated obligations at December 31, 2003.

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 (loss) at December 31, 2003. Foreign currency translation adjustments on the Brazil Generating Facility's U.S. dollar denominated borrowings payable to the subsidiary of $20.0 million at December 31, 2003, are recorded in accumulated other comprehensive income (loss).

The investment of Centennial International in the Brazil Generating Facility at December 31, 2003, was approximately $25.2 million including undistributed earnings of $4.6 million. Centennial has guaranteed Brazil Generating Facility obligations and loans of approximately $45.5 million as of December 31, 2003.

A portion of the Brazil Generating Facility's foreign currency exchange risk is being managed through contractual provisions, which are largely indexed to the U.S. dollar, contained in the Brazil Generating Facility's power purchase agreement with Petrobras. The Brazil Generating Facility has also historically used derivative instruments to manage a portion of its foreign currency risk and may utilize such instruments in the future.

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.

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

Warren L. Robinson
Executive Vice President
and Chief Financial Officer

Years ended December 31,	2003	2002	2001
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$ 641,062	$ 459,409	$ 903,334
Utility services, natural gas and oil production, construction materials and mining and other	1,711,127	1,572,128	1,320,298
	2,352,189	2,031,537	2,223,632
Operating expenses:			
Fuel and purchased power	62,037	56,010	57,393
Purchased natural gas sold	184,171	92,528	529,356
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	141,307	129,845	129,372
Utility services, natural gas and oil production, construction materials and mining and other	1,384,015	1,263,183	1,038,899
Depreciation, depletion and amortization	188,337	157,961	139,917
Taxes, other than income	80,250	65,893	55,427
	2,040,117	1,765,420	1,950,364
Operating income	312,072	266,117	273,268
Other income – net (Note 1)	22,207	13,572	26,821
Interest expense	52,794	45,015	45,899
Income before income taxes	281,485	234,674	254,190
Income taxes	98,572	86,230	98,341
Income before cumulative effect of accounting change	182,913	148,444	155,849
Cumulative effect of accounting change (Note 9)	(7,589)	–	–
Net income	175,324	148,444	155,849
Dividends on preferred stocks	717	756	762
Earnings on common stock	$ 174,607	$ 147,688	$ 155,087
Earnings per common share – basic:			
Earnings before cumulative effect of accounting change	$ 1.64	$ 1.39	$ 1.54
Cumulative effect of accounting change	(.07)	–	–
Earnings per common share – basic	$ 1.57	$ 1.39	$ 1.54
Earnings per common share – diluted:			
Earnings before cumulative effect of accounting change	$ 1.62	$ 1.38	$ 1.52
Cumulative effect of accounting change	(.07)	–	–
Earnings per common share – diluted	$ 1.55	$ 1.38	$ 1.52
Dividends per common share	$ .6600	$ .6266	$ .6000
Weighted average common shares outstanding – basic	111,483	106,115	100,908
Weighted average common shares outstanding – diluted	112,460	106,863	101,803
Pro forma amounts assuming retroactive application of accounting change:			
Net income	$ 182,913	$ 146,052	$ 152,933
Earnings per common share – basic	$ 1.64	$ 1.37	$ 1.51
Earnings per common share – diluted	$ 1.62	$ 1.36	$ 1.49

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

December 31,	2003	2002
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 86,341	$ 67,556
Receivables, net	357,677	325,395
Inventories	114,051	93,123
Deferred income taxes	3,104	8,877
Prepayments and other current assets	52,367	42,597
	613,540	537,548
Investments	44,975	42,864
Property, plant and equipment	3,397,619	2,961,808
Less accumulated depreciation, depletion and amortization	1,175,326	1,019,438
	2,222,293	1,942,370
Deferred charges and other assets:		
Goodwill (Note 3)	199,427	190,999
Other intangible assets, net (Note 3)	193,454	176,164
Other	106,903	106,976
	499,784	474,139
	$3,380,592	$2,996,921
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings (Note 7)	$ –	$ 20,000
Long-term debt and preferred stock due within one year	27,646	22,183
Accounts payable	150,316	132,120
Taxes payable	15,358	13,108
Dividends payable	19,442	17,959
Other accrued liabilities	101,299	94,275
	314,061	299,645
Long-term debt (Note 8)	939,450	819,558
Deferred credits and other liabilities:		
Deferred income taxes	444,779	374,097
Other liabilities	231,666	203,676
	676,445	577,773
Preferred stock subject to mandatory redemption (Note 10)	–	1,200
Commitments and contingencies (Notes 16, 18 and 19)		
Stockholders' equity:		
Preferred stocks (Note 10)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 11)		
Authorized – 250,000,000 shares, $1.00 par value		
Issued – 113,716,632 shares in 2003 and 74,282,038 shares in 2002	113,717	74,282
Other paid-in capital	757,787	748,095
Retained earnings	575,287	474,798
Accumulated other comprehensive loss	(7,529)	(9,804)
Treasury stock at cost – 359,281 shares in 2003 and 239,521 shares in 2002	(3,626)	(3,626)
Total common stockholders' equity	1,435,636	1,283,745
Total stockholders' equity	1,450,636	1,298,745
	$3,380,592	$2,996,921

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

Years ended December 31, 2003, 2002 and 2001

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Treasury Stock Amount	Total
				(In thousands, except shares)				
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
Comprehensive income:								
Net income	–	–	–	175,324	–	–	–	175,324
Other comprehensive income, net of tax –								
Net unrealized gain on derivative instruments qualifying as hedges	–	–	–	–	1,206	–	–	1,206
Minimum pension liability adjustment	–	–	–	–	21	–	–	21
Foreign currency translation adjustment	–	–	–	–	1,048	–	–	1,048
Total comprehensive income	–	–	–	–	–	–	–	177,599
Dividends on preferred stocks	–	–	–	(717)	–	–	–	(717)
Dividends on common stock	–	–	–	(74,118)	–	–	–	(74,118)
Issuance of common stock, net (pre-split)	1,442,220	1,442	45,260	–	–	–	–	46,702
Three-for-two common stock split (Note 11)	37,862,129	37,862	(37,862)	–	–	(119,760)	–	–
Issuance of common stock, net (post-split)	130,245	131	2,294	–	–	–	–	2,425
Balance at December 31, 2003	113,716,632	$113,717	$757,787	$575,287	$(7,529)	(359,281)	$(3,626)	$1,435,636

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

Years ended December 31,	2003	2002	2001
		(In thousands)	
Operating activities:			
Net income	$ 175,324	$ 148,444	$ 155,849
Cumulative effect of accounting change	7,589	–	–
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	188,337	157,961	139,917
Deferred income taxes	64,587	30,759	21,014
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(9,572)	(19,739)	127,267
Inventories	(13,023)	6,537	(26,540)
Other current assets	(13,383)	(5,562)	(2,792)
Accounts payable	2,748	11,600	(90,576)
Other current liabilities	10,486	(9,499)	34,331
Other noncurrent changes	5,304	5,830	(9,916)
Net cash provided by operating activities	418,397	326,331	348,554
Investing activities:			
Capital expenditures	(313,053)	(276,776)	(269,542)
Acquisitions, net of cash acquired	(132,653)	(92,657)	(112,743)
Net proceeds from sale or disposition of property	14,439	16,217	51,641
Investments	2,491	(4,666)	2,760
Additions to notes receivable	–	–	(23,813)
Proceeds from notes receivable	7,812	4,000	4,000
Net cash used in investing activities	(420,964)	(353,882)	(347,697)
Financing activities:			
Net change in short-term borrowings	(20,000)	20,000	(8,000)
Issuance of long-term debt	219,895	129,072	122,283
Repayment of long-term debt	(105,740)	(82,523)	(115,062)
Retirement of preferred stock	–	(100)	(100)
Proceeds from issuance of common stock, net	568	55,134	67,176
Dividends paid	(73,371)	(68,287)	(61,855)
Net cash provided by financing activities	21,352	53,296	4,442
Increase in cash and cash equivalents	18,785	25,745	5,299
Cash and cash equivalents – beginning of year	67,556	41,811	36,512
Cash and cash equivalents – end of year	$ 86,341	$ 67,556	$ 41,811

The accompanying notes are an integral part of these consolidated financial 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 businesses: electric, natural gas distribution, utility services, pipeline and energy services, natural gas and oil production, construction materials and mining, and independent power production and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Utility services, natural gas and oil production, construction materials and mining, and independent power production and other are nonregulated. For further descriptions of the Company's businesses, see Note 14. 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 certain investments including its 49 percent interest in MPX Participacoes, 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 investments, see new accounting standards in Note 1, as well as 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 (SFAS) No. 71, "Accounting for the Effects of Regulation." 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 in 2001, as discussed in Note 14, 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, 2003 and 2002, was $8.1 million and $8.2 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 $19.6 million at December 31, 2003, and $18.2 million at December 31, 2002. The remainder of natural gas in underground storage was included in other assets and was $42.6 million at December 31, 2003, and $42.2 million at December 31, 2002.

Inventories

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $54.7 million and $39.6 million, materials and supplies of $27.2 million and $23.0 million, and other inventories of $12.6 million and $12.3 million, as of December 31, 2003 and 2002, 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. Acquired aggregate reserves at the Company's construction materials and mining business are classified based on type of ownership. Owned mineral rights are classified as property, plant and equipment, whereas leased mineral rights are classified as other intangible assets, net. For more information on other intangible assets, net, see Note 3. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset 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 in natural gas and oil properties in Note 1, 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 $7.4 million, $7.6 million and $6.6 million in 2003, 2002 and 2001, 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, which are amortized on the units-of-production method based on total reserves.

Property, plant and equipment at December 31, 2003 and 2002, was as follows:

	2003	2002	Estimated Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	**$ 639,893**	$ 619,230	4–50
Natural gas distribution:			
Natural gas distribution plant	**252,591**	244,930	4–40
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities	**340,841**	262,971	3–70
Nonregulated:			
Utility services:			
Land	**2,505**	2,601	–
Buildings and improvements	**10,123**	8,768	10–40
Machinery, vehicles and equipment	**58,843**	54,833	2–10
Other	**5,400**	4,458	3–10
Pipeline and energy services:			
Natural gas gathering and other facilities	**119,613**	108,179	3–20
Energy services	**1,339**	1,270	3–15
Natural gas and oil production:			
Natural gas and oil properties	**862,839**	748,843	*(a)*
Other	**8,518**	6,945	5–7
Construction materials and mining:			
Land	**89,545**	85,376	–
Buildings and improvements	**48,907**	43,144	1–40
Machinery, vehicles and equipment	**569,295**	493,349	1–25
Construction in progress	**14,392**	10,151	–
Depletable reserves	**171,841**	172,235	*(b)*
Independent power production and other:			
Electric generation	**153,947**	58,000	5–30
Construction in progress	**29,805**	19,342	–
Land	**2,001**	2,001	–
Other	**15,381**	15,182	3–20
Less accumulated depreciation, depletion and amortization	**1,175,326**	1,019,438	
Net property, plant and equipment	**$2,222,293**	$1,942,370	

(a) Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent rate of $.89, $.80, and $.78 for the years ended December 31, 2003, 2002 and 2001, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $104,339 and $145,692 were excluded from amortization at December 31, 2003 and 2002, respectively.

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

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. No long-lived assets have been impaired and, accordingly, no impairment losses have been recorded in 2003, 2002 and 2001. 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 SFAS No. 142, "Goodwill and Other Intangibles," 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, 2003 and 2002, and determined that no impairments existed at those dates. Therefore, no impairment loss has been recorded for the years ended December 31, 2003 and 2002. For more information on goodwill, see Note 3.

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, 2003 and 2002, 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, 2003, could result in a future write-down of the Company's natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2003, in total and by year in which such costs were incurred:

		Year Costs Incurred			
	Total	2003	2002	2001	2000 and prior
			(In thousands)		
Acquisition	$ 48,355	$ 630	$17,108	$ –	$30,617
Development	39,160	28,351	5,120	–	5,689
Exploration	4,885	4,828	–	23	34
Capitalized interest	11,939	5,642	6,297	–	–
Total costs not subject to amortization	$104,339	$39,451	$28,525	$23	$36,340

Costs not subject to amortization as of December 31, 2003, consisted primarily of lease acquisition costs, unevaluated drilling costs and capitalized interest associated with coalbed development in the Powder River Basin of Montana and Wyoming. The Company expects that the majority of these costs will be evaluated over the next three- to five-year period and included in the amortization base as the properties are developed and evaluated and proved reserves are established or impairment is determined.

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 later. 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. Revenues at the independent power production operations are recognized based on electricity delivered and capacity provided, pursuant to contractual commitments. 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 $31.8 million and $19.4 million for the years ended December 31, 2003 and 2002, respectively, represents revenues recognized in excess of amounts billed and was included in receivables, net. Billings in excess of costs on uncompleted contracts of $20.4 million and $24.5 million for the years ended December 31, 2003 and 2002, 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 $34.3 million and $25.6 million as of December 31, 2003 and 2002, respectively, which are expected to be paid within one year or less.

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 2003, 2002 and 2001, was $3.9 million, $3.4 million and $2.9 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 recoverable through rate adjustments amounted to $10.5 million at December 31, 2003, which is included in prepayments and other current assets. Natural gas costs refundable through rate adjustments amounted to $2.4 million at December 31, 2002, which is included in other accrued liabilities.

NOTE 1 (CONTINUED)

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 claims first-made basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and claims incurred but not reported.

Other income – net

Other income – net consisted of the following:

Years ended December 31,	2003	2002	2001
		(In thousands)	
Interest and dividend income	**$ 6,722**	$ 8,160	$ 5,734
Earnings from equity method investments (Note 2)	**5,968**	1,341	154
Other income	**9,517**	4,071	20,933
Total other income – net	**$22,207**	$13,572	$26,821

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 SFAS No. 109, "Accounting for Income Taxes," have been recorded as a regulatory liability and are included in other 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.

Foreign currency translation adjustment

The functional currency of the Company's investment in a 220-megawatt natural gas-fired electric generating facility 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 (loss) 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.

Common stock split

On August 14, 2003, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 11.

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, restricted stock grants and performance share awards. For the years ended December 31, 2003, 2002 and 2001, 209,805 shares, 3,674,925 shares and 225,945 shares, respectively, with an average exercise price of $24.56, $20.08 and $24.57, 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 years ended December 31, 2003, 2002 and 2001, 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. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. Compensation expense recognized for awards granted on or after January 1, 2003, for the year ended December 31, 2003, was $41,000 (after tax).

As permitted by SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of SFAS No. 123," the Company accounts for stock options granted prior to January 1, 2003, under APB Opinion No. 25, "Accounting for Stock Issued to Employees." No compensation expense has been recognized for stock options granted prior to January 1, 2003, as the options granted had an exercise price equal to the market value of the underlying common stock on the date of the grant.

Since the Company adopted SFAS No. 123 effective January 1, 2003, for newly granted options only, the following table illustrates the effect on earnings and earnings per common share for the years ended December 31, 2003, 2002 and 2001, as if the Company had applied SFAS No. 123 and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant:

	2003	2002	2001
	(In thousands, except per share amounts)		
Earnings on common stock, as reported	**$174,607**	$147,688	$155,087
Stock-based compensation expense included in reported earnings, net of related tax effects	**41**	–	–
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	**(2,139)**	(2,862)	(3,799)
Pro forma earnings on common stock	**$172,509**	$144,826	$151,288
Earnings per common share – basic – as reported:			
Earnings before cumulative effect of accounting change	**$ 1.64**	$ 1.39	$ 1.54
Cumulative effect of accounting change	**(.07)**	–	–
Earnings per common share – basic	**$ 1.57**	$ 1.39	$ 1.54
Earnings per common share – basic – pro forma:			
Earnings before cumulative effect of accounting change	**$ 1.62**	$ 1.36	$ 1.50
Cumulative effect of accounting change	**(.07)**	–	–
Earnings per common share – basic	**$ 1.55**	$ 1.36	$ 1.50
Earnings per common share – diluted – as reported:			
Earnings before cumulative effect of accounting change	**$ 1.62**	$ 1.38	$ 1.52
Cumulative effect of accounting change	**(.07)**	–	–
Earnings per common share – diluted	**$ 1.55**	$ 1.38	$ 1.52
Earnings per common share – diluted – pro forma:			
Earnings before cumulative effect of accounting change	**$ 1.60**	$ 1.36	$ 1.49
Cumulative effect of accounting change	**(.07)**	–	–
Earnings per common share – diluted	**$ 1.53**	$ 1.36	$ 1.49

For more information on the Company's stock-based compensation, see Note 12.

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; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments, including 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,	**2003**	2002	2001
		(In thousands)	
Interest, net of amount capitalized	**$47,474**	$37,788	$42,267
Income taxes	**$31,737**	$60,988	$75,284

Reclassifications

The Consolidated Statements of Income have been reclassified to include additional disclosures relating to the components comprising operating revenues and operation and maintenance expense.

Certain other 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

The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123, and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. For a discussion of the effect of the adoption of the fair value recognition provisions of SFAS No. 123 on earnings and earnings per share, see stock-based compensation in Note 1.

In June 2001, the Financial Accounting Standards Board (FASB) approved SFAS No. 143, "Accounting for Asset Retirement Obligations." 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. SFAS No. 143 is effective for fiscal years beginning after June 15, 2002. For more information on the adoption of SFAS No. 143, see Note 9.

In April 2002, the FASB approved SFAS No. 145, "Rescission of FASB Statements No. 4, 44 and 64, Amendment of FASB Statement No. 13, and Technical Corrections." 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 adoption of SFAS No. 145 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" (FIN 45). FIN 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. FIN 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 FIN 45 but are subject to its disclosure requirements. The initial recognition and initial measurement provisions of FIN 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 FIN 45 is not required to be revised or restated. The disclosure requirements in FIN 45 are effective for financial statements of interim or annual periods ended after December 15, 2002. The Company is applying the initial recognition and initial measurement provisions of FIN 45 to guarantees issued or modified after December 31, 2002. For more information on the Company's guarantees and the disclosure requirements of FIN 45, as applicable to the Company, see Note 19.

In April 2003, the FASB issued SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities." SFAS No. 149 provides clarification on the financial accounting and reporting of derivative instruments, including certain derivative instruments embedded in other contracts, and hedging activities; and requires contracts with similar characteristics to be accounted for on a comparable basis. SFAS No. 149 is generally effective for contracts entered into or modified after June 30, 2003, and for hedging relationships designated after June 30, 2003. The adoption of SFAS No. 149 did not have a material effect on the Company's financial position or results of operations.

In May 2003, the FASB issued SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of Both Liabilities and Equity." SFAS No. 150 establishes standards for how an issuer classifies and measures certain financial instruments with characteristics of both liabilities and equity. It requires that an issuer classify a financial instrument that is within the scope of SFAS No. 150 as a liability (or an asset in some circumstances). SFAS No. 150 is effective for financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The Company will apply SFAS No. 150 to any financial instruments entered into or modified after May 31, 2003. Beginning in 2003, the Company reported its preferred stock subject to mandatory redemption as a liability in accordance with SFAS No. 150. The transition to SFAS No. 150 did not have a material effect on the Company's financial position or results of operations.

In December 2003, the FASB issued FASB Interpretation No. 46 (revised 2003), "Consolidation of Variable Interest Entities" (FIN 46 (revised)), which revised FASB Interpretation No. 46, "Consolidation of Variable Interest Entities" (FIN 46). FIN 46 (revised) clarifies the application of Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated support. An enterprise shall consolidate a variable interest entity if that enterprise is the primary beneficiary. An enterprise is considered the primary beneficiary if it has a variable interest that will absorb a majority of the entity's expected losses, receive a majority of the entity's expected residual returns or both.

FIN 46 (revised) shall be applied to all entities subject to FIN 46 (revised) no later than the end of the first reporting period that ends after March 15, 2004. However, an entity that applied FIN 46 to an entity prior to the effective date of FIN 46 (revised) shall either continue to apply FIN 46 until the effective date of FIN 46 (revised) or apply FIN 46 (revised) at an earlier date.

NOTE 1
(CONTINUED)

The Company had evaluated the provisions of FIN 46 and determined that MPX is a variable interest entity. MPX was formed in August 2001, as a result of MDU Brasil Ltda. (MDU Brasil), an indirect wholly owned Brazilian subsidiary of the Company, entering into a joint venture agreement with a Brazilian firm. MDU Brasil has a 49 percent interest in MPX. Although the Company has determined that MPX is a variable interest entity, MDU Brasil is not considered the primary beneficiary of MPX because MDU Brasil does not absorb a majority of MPX's expected losses, receive a majority of MPX's expected residual returns or both. Therefore, MDU Brasil does not have a controlling financial interest in MPX and is not required to consolidate MPX in its financial statements. MPX is being accounted for under the equity method of accounting. For more information on this equity method investment, see Note 2. The adoption of FIN 46 did not have an effect on the Company's financial position or results of operations. The Company will continue to apply FIN 46 until the effective date of FIN 46 (revised).

In December 2003, the FASB issued SFAS No. 132 (revised 2003), "Employers' Disclosures about Pension and Other Postretirement Benefits." SFAS No. 132 (revised 2003) retains the disclosure requirements contained in SFAS No. 132, "Employers' Disclosures about Pensions and Other Postretirement Benefits," and requires additional disclosures about the assets, obligations, cash flows and net periodic benefit cost of defined benefit pension plans and other postretirement benefit plans. SFAS No. 132 (revised 2003) is effective for financial statements with fiscal years ending after December 15, 2003. The interim-period disclosures required by SFAS No. 132 (revised 2003) are effective for interim periods beginning after December 15, 2003. The Company applied SFAS No. 132 (revised 2003) to its consolidated financial statements issued after December 15, 2003. For more information on the Company's pension and other postretirement benefits, see Note 16.

In January 2004, the FASB issued FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FASB Staff Position No. FAS 106-1 permits a sponsor of a postretirement health care plan that provides a prescription drug benefit to make a one-time election to defer accounting for the effects of the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (2003 Medicare Act). SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other than Pension," requires enacted changes in relevant laws to be considered in current period measurements of postretirement benefit costs and accumulated postretirement benefit obligation. The Company provides prescription drug benefits to certain eligible employees and has elected the one-time deferral of accounting for the effects of the 2003 Medicare Act. These consolidated financial statements and accompanying notes do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plans. The Company intends to analyze the 2003 Medicare Act, along with the authoritative guidance, when issued, to determine if its benefit plans need to be amended and how to record the effects of the 2003 Medicare Act. Specific guidance on the accounting for the federal subsidy provided by the 2003 Medicare Act is pending and that guidance, when issued, could require the Company to change previously reported postretirement benefit information. For more information on the Company's postretirement benefits, see Note 16.

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, minimum pension liability adjustments and foreign currency translation adjustments.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2003, 2002 and 2001, were as follows:

	2003	2002	2001
		(In thousands)	
Other comprehensive income (loss):			
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 $2,132, $2,903 and $1,448 in 2003, 2002 and 2001, respectively	(3,335)	(4,541)	2,218
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $2,903, $1,448 and $3,970 in 2003, 2002 and 2001, respectively	(4,541)	2,218	(6,080)
Net unrealized gain (loss) on derivative instruments qualifying as hedges	1,206	(6,759)	2,218
Minimum pension liability adjustment, net of tax of $38 and $2,876 in 2003 and 2002, respectively	21	(4,464)	–
Foreign currency translation adjustment	1,048	(799)	–
Total other comprehensive income (loss)	$ 2,275	$(12,022)	$ 2,218

The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2003, 2002 and 2001, 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, 2001	$ 2,218	$ –	$ –	$ 2,218
Balance at December 31, 2002	$(4,541)	$(4,464)	$(799)	$(9,804)
Balance at December 31, 2003	**$(3,335)**	**$(4,443)**	**$ 249**	**$(7,529)**

NOTE 2 EQUITY METHOD INVESTMENTS

The Company has a number of equity method investments, including MPX, which was formed in August 2001 when MDU Brasil entered into a joint venture agreement with a Brazilian firm. MDU Brasil has a 49 percent interest in MPX, which is being accounted for under the equity method of accounting, as discussed in Note 1. MPX, through a wholly owned subsidiary, owns a 220-megawatt natural gas-fired electric generating facility (Brazil Generating Facility) in the Brazilian state of Ceara. At December 31, 2003, MPX has assets of approximately $109.6 million and long-term debt of approximately $86.8 million, including a loan of $20.0 million from Centennial Energy Resources International Inc, an indirect wholly owned subsidiary of the Company. Petrobras, the Brazilian state-controlled energy company, has agreed to purchase all of the capacity and market all of the Brazil Generating Facility's energy. The power purchase agreement with Petrobras expires in May 2008. Petrobras also is under contract to supply natural gas to the Brazil Generating Facility during the term of the power purchase agreement. This natural gas supply contract is renewable by a wholly owned subsidiary of MPX for an additional 13 years. The functional currency for the Brazil Generating Facility 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. For the year ended December 31, 2003, the Company's 49 percent share of the loss from the change in the fair value

NOTE 2 (CONTINUED)

of the embedded derivative in the power purchase agreement was $11.3 million (after tax). For the year ended December 31, 2002, the Company's 49 percent share of the gain from the change in the fair value of the embedded derivative in the power purchase agreement was $13.6 million (after tax). The Company's 49 percent share of the foreign currency gain resulting from the revaluation of the Brazilian real was $2.8 million (after tax) for the year ended December 31, 2003. The Company's 49 percent share of the foreign currency loss resulting from devaluation of the Brazilian real was $9.4 million (after tax) for the year ended December 31, 2002. The Company's investment in the Brazil Generating Facility was approximately $25.2 million, including undistributed earnings of $4.6 million at December 31, 2003. The Company's investment in the Brazil Generating Facility was approximately $27.8 million at December 31, 2002.

The Company's share of income from its equity method investments, including MPX, was $6.0 million, $1.3 million and $154,000 for the years ended December 31, 2003, 2002 and 2001, respectively, and was included in other income – net.

NOTE 3 GOODWILL AND OTHER INTANGIBLE ASSETS

On January 1, 2002, in accordance with SFAS No. 142, "Goodwill and Other Intangible Assets," 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, 2001. 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, 2003, 2002 and 2001, were as follows:

	2003	2002	2001
	(In thousands, except per share amounts)		
Reported earnings on common stock	**$174,607**	$147,688	$155,087
Add: Goodwill amortization, net of tax	–	–	3,649
Adjusted earnings on common stock	**$174,607**	$147,688	$158,736
Reported earnings per common share – basic	**$ 1.57**	$ 1.39	$ 1.54
Add: Goodwill amortization, net of tax	–	–	.03
Adjusted earnings per common share – basic	**$ 1.57**	$ 1.39	$ 1.57
Reported earnings per common share – diluted	**$ 1.55**	$ 1.38	$ 1.52
Add: Goodwill amortization, net of tax	–	–	.04
Adjusted earnings per common share – diluted	**$ 1.55**	$ 1.38	$ 1.56

The changes in the carrying amount of goodwill for the year ended December 31, 2003, were as follows:

	Balance as of January 1, 2003	Goodwill Acquired During the Year	Balance as of December 31, 2003
		(In thousands)	
Electric	$ –	$ –	$ –
Natural gas distribution	–	–	–
Utility services	62,487	117	62,604
Pipeline and energy services	9,494	–	9,494
Natural gas and oil production	–	–	–
Construction materials and mining	111,887	8,311	120,198
Independent power production and other	7,131	–	7,131
Total	$190,999	$8,428	$199,427

The changes in the carrying amount of goodwill for the year ended December 31, 2002, 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 and other	–	7,131	7,131
Total	$173,997	$17,002	$190,999

Other intangible assets at December 31, 2003 and 2002, were as follows:

	2003	2002
	(In thousands)	
Amortizable intangible assets:		
Leasehold rights	**$186,419**	$172,496
Accumulated amortization	**(11,779)**	(7,494)
	174,640	165,002
Noncompete agreements	**12,075**	12,075
Accumulated amortization	**(9,690)**	(9,366)
	2,385	2,709
Other	**17,734**	7,224
Accumulated amortization	**(2,265)**	(374)
	15,469	6,850
Unamortizable intangible assets	**960**	1,603
Total	**$193,454**	$176,164

Acquired aggregate reserves at our construction materials and mining business are classified based on type of ownership. Owned mineral rights are classified as property, plant and equipment, whereas leased mineral rights are classified as leasehold rights in other intangible assets, net.

The unamortizable intangible assets were recognized in accordance with SFAS No. 87, "Employers' Accounting for Pensions," which requires that if an additional minimum liability is recognized an equal amount shall be recognized as an intangible asset, provided that the asset recognized shall not exceed the amount of unrecognized prior service cost. The unamortizable intangible asset will be eliminated or adjusted as necessary upon a new determination of the amount of additional liability.

Amortization expense for amortizable intangible assets for the years ended December 31, 2003 and 2002, was $5.9 million and $3.4 million, respectively. Estimated amortization expense for amortizable intangible assets is $6.2 million in 2004, $6.4 million in 2005, $5.2 million in 2006, $5.2 million in 2007, $5.2 million in 2008 and $164.3 million thereafter.

SFAS No. 142 discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. SFAS No. 141, "Business Combinations," and SFAS No. 142 clarify that more assets should be distinguished and classified between tangible and intangible. The Company did not change or reclassify

NOTE 3 (CONTINUED)

contractual mineral rights included in property, plant and equipment related to its natural gas and oil production business upon adoption of SFAS No. 142. The Company has included such mineral rights as part of property, plant and equipment under the full-cost method of accounting for natural gas and oil properties. An issue has arisen within the natural gas and oil industry as to whether contractual mineral rights under SFAS No. 142 should be classified as intangible rather than as part of property, plant and equipment. This accounting matter is anticipated to be addressed by the FASB's Emerging Issues Task Force. The resolution of this matter may result in certain reclassifications of amounts in the Consolidated Balance Sheets, as well as changes to Notes to Consolidated Financial Statements in the future. The applicable provisions of SFAS No. 141 and SFAS No. 142 only affect the balance sheet and associated footnote disclosure, so any reclassifications that might be required in the future will not affect the Company's cash flows or results of operations. The Company believes that the resolution of this matter will not have a material effect on the Company's financial position because the mineral rights acquired by its natural gas and oil production business after the June 30, 2001, effective date of SFAS No. 142 were not material.

NOTE 4 REGULATORY ASSETS AND LIABILITIES

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

	2003	2002
	(In thousands)	
Regulatory assets:		
Deferred income taxes	**$ 29,850**	$ 27,378
Natural gas costs recoverable through rate adjustments	**10,519**	–
Long-term debt refinancing costs	**4,519**	5,627
Plant costs	**2,697**	2,330
Postretirement benefit costs	**562**	616
Other	**7,159**	4,788
Total regulatory assets	**55,306**	40,739
Regulatory liabilities:		
Plant removal and decommissioning costs	**76,176**	68,551
Reserves for regulatory matters	**11,970**	9,856
Taxes refundable to customers	**11,751**	11,699
Deferred income taxes	**10,663**	5,491
Natural gas costs refundable through rate adjustments	**–**	2,396
Other	**658**	2,779
Total regulatory liabilities	**111,218**	100,772
Net regulatory position	**$(55,912)**	$(60,033)

As of December 31, 2003, 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 19 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, "Accounting for Derivative Instruments and Hedging Activities," as amended, 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, 2003, an indirect wholly owned subsidiary of the Company held derivative instruments designated as cash flow hedging instruments.

Hedging activities

The 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 was 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.

For the years ended December 31, 2003, 2002 and 2001, the subsidiary of the Company recognized the ineffectiveness of cash flow hedges, which is included in operating revenues for the natural gas and oil price swap and collar agreements. For the years ended December 31, 2003, 2002 and 2001, the amount of hedge ineffectiveness recognized was immaterial. For the years ended December 31, 2003, 2002 and 2001, the subsidiary 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, 2003, 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 $3.3 million will be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

NOTE 5 (CONTINUED)

Foreign currency derivative

MDU Brasil has a 49 percent equity investment in the Brazil Generating Facility, which has a portion of its borrowings and payables denominated in U.S. dollars. MDU Brasil has exposure to currency exchange risk as a result of fluctuations in currency exchange rates between the U.S. dollar and the Brazilian real. On August 12, 2002, MDU Brasil 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 term of the collar agreement was from August 12, 2002, through February 3, 2003, and the collar agreement settled on February 3, 2003. The foreign currency collar agreement was not designated as a hedge and was recorded at fair value on the Consolidated Balance Sheets. Gains or losses on this derivative instrument were recorded in other income – net. The Company recorded a gain of $39,000 (after tax) on the foreign currency collar agreement for the year ended December 31, 2003, and a gain of $566,000 (after tax) 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 year ended December 31, 2001.

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. As discussed in Note 1, the Company, upon adoption of SFAS No.150 in 2003, began reporting its preferred stock subject to mandatory redemption as a liability. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included in current liabilities at December 31, 2003 and 2002. 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 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:

	2003		2002	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	**$967,096**	**$1,012,547**	$841,641	$888,066
Preferred stock subject to mandatory redemption	**$ –**	**$ –**	$ 1,300	$ 1,168
Natural gas and oil price swap and collar agreements	**$ (5,467)**	**$ (5,467)**	$ (7,444)	$ (7,444)
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.

At December 31, 2002, $8.0 million of MDU Resources Group, Inc. (MDU Resources) commercial paper program borrowings were classified as short-term borrowings. The commercial paper borrowings classified as short term were supported by short-term bank lines of credit. There were no amounts outstanding under the bank lines of credit at December 31, 2002. MDU Resources did not have any short-term bank lines of credit at December 31, 2003. For more information on MDU Resources' commercial paper program, see Note 8.

International operations

A subsidiary of the Company had a short-term credit agreement that expired in 2003. Under this agreement $12.0 million was outstanding at December 31, 2002.

NOTE 8 LONG-TERM DEBT AND INDENTURE PROVISIONS

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

	2003	2002
	(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
Senior Notes, 5.98%, due December 15, 2033	**30,000**	–
Total first mortgage bonds and notes	**160,850**	130,850
Senior notes at a weighted average rate of 6.24%, due on dates ranging from October 30, 2004 to October 30, 2018	**718,000**	549,100
Commercial paper at a weighted average rate of 1.12%, supported by revolving credit agreements	**72,500**	151,900
Term credit agreements at a weighted average rate of 5.14%, due on dates ranging from July 15, 2004 to December 1, 2013	**14,286**	7,873
Pollution control note obligation, 6.20%, due March 1, 2004	**1,500**	2,000
Discount	**(40)**	(82)
Total long-term debt	**967,096**	841,641
Less current maturities	**27,646**	22,083
Net long-term debt	**$939,450**	$819,558

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2003, aggregate $27.6 million in 2004; $70.9 million in 2005; $173.2 million in 2006; $105.8 million in 2007; $160.2 million in 2008 and $429.4 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, 2003.

MDU Resources Group, Inc.

MDU Resources has a revolving credit agreement with various banks totaling $90 million at December 31, 2003. There were no amounts outstanding under the credit agreement at December 31, 2003 and 2002. The credit agreement supports MDU Resources' $75 million commercial paper program. Under the MDU Resources' commercial paper program, $40 million was outstanding at December 31, 2003, which was classified as long-term debt, and $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. As discussed in Note 7, the commercial paper borrowings classified as short term were supported by 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 MDU Resources commercial paper borrowings and as further supported by the credit agreement, which expires on July 18, 2006.

NOTE 8 (CONTINUED)

In order to borrow under the 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, 2003.

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

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, 2003, MDU Resources could have issued approximately $313 million of additional first mortgage bonds.

Approximately $421.2 million of the Company's net electric and natural gas distribution properties at December 31, 2003, with certain exceptions, are subject to the lien of the Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustee, and are subject to the junior lien of the Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York, as trustee.

Centennial Energy Holdings, Inc.

Centennial Energy Holdings, Inc. (Centennial) has two revolving credit agreements with various banks that support $275 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2003 or 2002. Under the Centennial commercial paper program, $32.5 million and $101.9 million were outstanding at December 31, 2003 and 2002, respectively. The Centennial commercial paper borrowings are classified as long-term debt 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 agreements. The Centennial credit agreements are for $137.5 million each. One of these agreements expires on September 3, 2004, and allows for subsequent borrowings up to a term of one year. The other agreement expires on September 5, 2006. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities.

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, $384.0 million was outstanding at December 31, 2003, and $360.6 million was outstanding at December 31, 2002. The amount outstanding under the uncommitted long-term master shelf agreement is included in senior notes in the preceding long-term debt table.

In order to borrow under Centennial's credit agreements 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, 2003.

Certain of Centennial's financing agreements 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 applicable agreements will be in default. Certain of Centennial's financing agreements 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, $55.0 million and $30.0 million was outstanding at December 31, 2003 and 2002, respectively.

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, 2003.

NOTE 9 ASSET RETIREMENT OBLIGATIONS

The Company adopted SFAS No. 143 on January 1, 2003, as discussed in Note 1. The Company recorded obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties and certain other obligations associated with leased properties. Removal costs associated with certain natural gas distribution, transmission, storage and gathering facilities have not been recognized as these facilities have been determined to have indeterminate useful lives.

Upon adoption of SFAS No. 143, the Company recorded an additional discounted liability of $22.5 million and a regulatory asset of $493,000, increased net property, plant and equipment by $9.6 million and recognized a one-time cumulative effect charge of $7.6 million (net of deferred income tax benefits of $4.8 million). The Company believes that any expenses under SFAS No. 143 as they relate to regulated operations will be recovered in rates over time and accordingly, deferred such expenses as a regulatory asset upon adoption. The Company will continue to defer those SFAS No. 143 expenses that it believes will be recovered in rates over time. In addition to the $22.5 million liability recorded upon the adoption of SFAS No. 143, the Company had previously recorded a $7.5 million liability related to retirement obligations.

A reconciliation of the Company's liability for the year ended December 31 was as follows:

	2003
	(In thousands)
Balance at January 1, 2003	$29,997
Liabilities incurred	2,405
Liabilities acquired	1,803
Liabilities settled	(1,555)
Accretion expense	1,906
Revisions in estimates	77
Balance at December 31, 2003	$34,633

This liability is included in other liabilities. If SFAS No. 143 had been in effect during 2002 and 2001, the Company's liability would have been approximately $30.0 million at December 31, 2002, and $27.0 million at December 31, 2001.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2003, was $5.1 million.

NOTE 10
PREFERRED STOCKS

Preferred stocks at December 31 were as follows:

	2003	2002
	(Dollars in thousands)	
Authorized:		
Preferred –		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A –		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference –		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
Subject to mandatory redemption –		
Preferred –		
5.10% Series – 13,000 shares in 2002	**$ –**	$ 1,300
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	**15,000**	16,300
Less sinking fund requirements	**–**	100
Net preferred stocks	**$15,000**	$16,200

As discussed in Note 1, the Company upon adoption of SFAS No. 150 in 2003, began reporting its preferred stock subject to mandatory redemption as a liability. Restatement of prior year information is not permitted under SFAS No. 150.

The 4.50% Series and 4.70% Series 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 at a redemption price, plus accrued dividends, of $105 and $102, respectively.

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

The affirmative vote of two-thirds of a series of the Company's outstanding preferred stock is necessary for amendments to the Company's charter or by-laws that adversely affect that series; creation of or increase in the amount of authorized stock ranking senior to that series (or an affirmative majority vote where the authorization relates to a new class of stock that ranks on parity with such series); a voluntary liquidation or sale of substantially all of the Company's assets; a merger or consolidation, with certain exceptions; or the partial retirement of that series of preferred stock when all dividends on that series of preferred stock have not been paid. The consent of the holders of a particular series is not required for such corporate actions if the equivalent vote of all outstanding series of preferred stock voting together has consented to the given action and no particular series is affected differently than any other series.

Subject to the foregoing, the holders of common stock exclusively possess all voting power. However, if cumulative dividends on preferred stock are in arrears, in whole or in part, for one year the holders of preferred stock would obtain the right to one vote per share until all dividends in arrears have been paid and current dividends have been declared and set aside.

NOTE 11 COMMON STOCK

On August 14, 2003, the Company's Board of Directors approved a three-for-two common stock split to be effected in the form of a 50 percent common stock dividend. The additional shares of common stock were distributed on October 29, 2003, to common stockholders of record on October 10, 2003. Common stock information appearing in the accompanying consolidated financial statements has been restated to give retroactive effect to the stock split. Additionally, preference share purchase rights have been appropriately adjusted to reflect the effects of the split.

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 Dividend Reinvestment and Direct Stock Purchase Plan (Stock Purchase Plan) provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The Company's 401(k) Retirement Plan (K-Plan) is partially funded with the Company's common stock. Since January 1, 2001, 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, 2003, there were 12.1 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 two-thirds of one one-thousandth of a share of Series B Preference Stock of the Company, without par value, at an exercise price of $125, 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 two-thirds 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 $.00667 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.

NOTE 12 STOCK-BASED COMPENSATION

The Company has stock option plans for directors, key employees and employees. In 2003, the Company adopted the fair value recognition provisions of SFAS No. 123 and began expensing the fair market value of stock options for all awards granted on or after January 1, 2003. As permitted by SFAS No. 148, the Company accounts for stock options granted prior to January 1, 2003, under APB Opinion No. 25.

For a discussion of the adoption of SFAS No. 123 and the effect on earnings and earnings per common share for the years ended December 31, 2003, 2002 and 2001, as if the Company had applied SFAS No. 123, and recognized compensation expense for all outstanding and unvested stock options based on the fair value at the date of grant, see Note 1.

Options granted to 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.

A summary of the status of the stock option plans at December 31, 2003, 2002 and 2001, and changes during the years then ended was as follows:

	2003		2002		2001	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	**4,861,268**	**$18.58**	5,208,311	$18.60	1,837,439	$13.74
Granted	**27,015**	**17.29**	160,605	19.15	4,039,680	20.09
Forfeited	**(188,486)**	**20.05**	(453,840)	19.77	(111,423)	18.16
Exercised	**(517,341)**	**13.88**	(53,808)	12.20	(557,385)	13.49
Balance at end of year	**4,182,456**	**19.09**	4,861,268	18.58	5,208,311	18.60
Exercisable at end of year	**611,404**	**$15.06**	1,135,050	$14.56	1,155,213	$14.27

Summarized information about stock options outstanding and exercisable as of December 31, 2003, 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
$ 8.22 – 13.00	23,451	2.5	$ 9.77	23,451	$ 9.77
13.01 – 17.00	647,085	4.3	14.13	511,453	14.15
17.01 – 21.00	3,302,115	7.2	19.77	36,000	19.54
21.01 – 25.70	209,805	7.2	24.56	40,500	25.70
Balance at end of year	4,182,456	6.7	19.09	611,404	15.06

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:

	2003	2002	2001
Weighted average fair value of options at grant date	**$4.67**	$5.38	$4.92
Weighted average risk-free interest rate	**3.91%**	5.14%	5.19%
Weighted average expected price volatility	**32.28%**	30.80%	26.05%
Weighted average expected dividend yield	**3.43%**	3.43%	3.53%
Expected life in years	**7**	7	7

In addition, the Company granted restricted stock awards under a long-term incentive plan and deferred compensation agreements totaling 525,588 shares in 2001. 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 grant in 2001 was $21.03. The Company also has granted stock awards totaling 31,855 shares, 21,390 shares and 19,009 shares in 2003, 2002 and 2001, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $21.40, $19.20 and $20.09, in 2003, 2002 and 2001, respectively. Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. Compensation expense recognized for restricted stock grants and stock grants was $4.8 million, $5.2 million and $4.9 million in 2003, 2002 and 2001, respectively.

In 2003, key employees of the Company were awarded performance share awards. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group. Target grants of performance shares were made for the following performance periods:

Grant Date	Performance Period	Target Grant of Shares
February 2003	2003–2004	57,655
February 2003	2003–2005	57,655

Participants may earn additional performance shares if the Company's total shareholder return exceeds that of the selected peer group. The final value of the performance units may vary according to the number of shares of Company stock that are ultimately granted based on the performance criteria. Compensation expense recognized for the performance share awards for the year ended December 31, 2003, was $879,000.

The Company is authorized to grant options, restricted stock and stock for up to 14.3 million shares of common stock and has granted options, restricted stock and stock on 6.2 million shares through December 31, 2003.

NOTE 13
INCOME TAXES

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

	2003	2002	2001
		(In thousands)	
Current:			
Federal	**$26,313**	$46,389	$66,211
State	**7,408**	9,082	11,160
Foreign	**264**	–	(44)
	33,985	55,471	77,327
Deferred:			
Income taxes –			
Federal	**55,660**	26,373	16,972
State	**9,861**	4,632	4,773
Foreign	**(338)**	338	–
Investment tax credit	**(596)**	(584)	(731)
	64,587	30,759	21,014
Total income tax expense	**$98,572**	$86,230	$98,341

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

	2003	2002
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 37,072**	$ 34,792
Accrued pension costs	**12,122**	12,112
Deferred compensation	**9,090**	6,395
Asset retirement obligations	**7,017**	263
Bad debts	**3,188**	2,798
Deferred investment tax credit	**954**	1,185
Other	**21,269**	18,444
Total deferred tax assets	**90,712**	75,989
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**406,589**	354,842
Basis differences on natural gas and oil producing properties	**105,826**	70,464
Regulatory matters	**10,663**	5,491
Other	**9,309**	10,412
Total deferred tax liabilities	**532,387**	441,209
Net deferred income tax liability	**$(441,675)**	$(365,220)

As of December 31, 2003 and 2002, 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, 2002, to December 31, 2003, to deferred income tax expense:

	2003
	(In thousands)
Net change in deferred income tax liability from the preceding table	**$ 76,455**
Deferred taxes associated with acquisitions	**(15,056)**
Deferred taxes associated with the cumulative effect of accounting change	**4,821**
Deferred taxes associated with other comprehensive income	**(809)**
Other	**(824)**
Deferred income tax expense for the period	**$ 64,587**

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,	**2003**		2002		2001	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	**$98,520**	**35.0**	$82,136	35.0	$88,966	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	**11,857**	**4.2**	10,279	4.4	11,311	4.5
Investment tax credit amortization	**(596)**	**(.2)**	(584)	(.3)	(731)	(.3)
Depletion allowance	**(3,117)**	**(1.1)**	(2,200)	(.9)	(1,820)	(.7)
Renewable electricity production credit	**(3,395)**	**(1.2)**	–	–	–	–
Other items	**(4,697)**	**(1.7)**	(3,401)	(1.5)	615	.2
Total income tax expense	**$98,572**	**35.0**	$86,230	36.7	$98,341	38.7

The Company considers earnings from its foreign equity method investment in a natural gas-fired electric generating 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 14 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. The Company has six reportable 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 separated independent power production and other operations from its reportable segments. The independent power production and other operations do not individually meet the criteria to be considered a reportable segment. Substantially all of the operations of independent power production and other began in 2002; therefore, financial information for years prior to 2002 has not been presented.

The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of an investment in a natural gas-fired electric generating facility 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 specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling and the manufacture and distribution of specialty equipment. 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 and around 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 performs integrated construction services, in the central and western United States and in the states of Alaska and Hawaii. The independent power production and other operations own electric generating facilities in the United States and have an investment in an electric generating facility in Brazil. Electric capacity and energy produced at these facilities are primarily sold under long-term contracts to nonaffiliated entities. These operations also include investments in opportunities that are not directly being pursued by the Company's other businesses.

In 2001, the Company sold its coal operations to Westmoreland Coal Company for $28.2 million in cash and recorded a gain of $10.3 million ($6.2 million after tax) included in other income – net. The sale of the Company's coal operations included active coal mines in North Dakota and Montana, coal sales agreements, reserves and mining equipment, and certain development rights at the Company's former Gascoyne Mine site in North Dakota. The Company retained ownership of lignite deposits and leases at its former Gascoyne Mine site in North Dakota, which were not part of the sale of the coal operations. The Gascoyne Mine site was closed in 1995 due to the cancellation of the coal sale contract. These lignite deposits are currently not being mined and are not associated with an operating mine. These lignite deposits are of a high moisture content and it is not economical to mine and ship the lignite to other distant markets. However, should a power plant be constructed near the area, the Company may have the opportunity to participate in supplying lignite to fuel a plant. As of December 31, 2003, Knife River had under ownership or lease, deposits of approximately 26.9 million tons of recoverable lignite coal.

NOTE 14
(CONTINUED)

The information below follows the same accounting policies as described in the Summary of Significant Accounting Policies. Information on the Company's businesses as of December 31 and for the years then ended was as follows:

	2003	2002	2001
		(In thousands)	
External operating revenues:			
Electric	$ 178,562	$ 162,616	$ 168,837
Natural gas distribution	274,608	186,569	255,389
Pipeline and energy services	187,892	110,224	479,108
	641,062	459,409	903,334
Utility services	434,177	458,660	364,746
Natural gas and oil production	140,281	148,158	148,653
Construction materials and mining	1,104,408	962,312	806,899 *(a)*
Independent power production and other	32,261	2,998	–
	1,711,127	1,572,128	1,320,298
Total external operating revenues	$2,352,189	$2,031,537	$2,223,632
Intersegment operating revenues:			
Electric	$ –	$ –	$ –
Natural gas distribution	–	–	–
Utility services	–	–	4
Pipeline and energy services	64,300	55,034	52,006
Natural gas and oil production	124,077	55,437	61,178
Construction materials and mining	–	–	–
Independent power production and other	2,728	3,778	–
Intersegment eliminations	(191,105)	(114,249)	(113,188)
Total intersegment operating revenues	$ –	$ –	$ –
Depreciation, depletion and amortization:			
Electric	$ 20,150	$ 19,537	$ 19,488
Natural gas distribution	10,044	9,940	9,337
Utility services	10,353	9,871	8,395
Pipeline and energy services	15,016	14,846	14,341
Natural gas and oil production	61,019	48,714	41,690
Construction materials and mining	63,601	54,334	46,666
Independent power production and other	8,154	719	–
Total depreciation, depletion and amortization	$ 188,337	$ 157,961	$ 139,917
Interest expense:			
Electric	$ 8,013	$ 7,621	$ 8,531
Natural gas distribution	3,936	4,364	3,727
Utility services	3,668	3,568	3,807
Pipeline and energy services	7,952	7,670	9,136
Natural gas and oil production	4,767	2,464	1,359
Construction materials and mining	18,747	18,422	19,339
Independent power production and other	5,865	1,122	–
Intersegment eliminations	(154)	(216)	–
Total interest expense	$ 52,794	$ 45,015	$ 45,899
Income taxes:			
Electric	$ 9,862	$ 9,501	$ 10,511
Natural gas distribution	1,823	(1,325)	1,067
Utility services	3,905	4,781	9,131
Pipeline and energy services	11,188	12,462	11,633
Natural gas and oil production	42,993	30,604	40,486
Construction materials and mining	28,168	29,415	25,513
Independent power production and other	633	792	–
Total income taxes	$ 98,572	$ 86,230	$ 98,341

	2003	2002	2001
		(In thousands)	
Cumulative effect of accounting change (Note 9):			
Electric	$ –	$ –	$ –
Natural gas distribution	–	–	–
Utility services	–	–	–
Pipeline and energy services	–	–	–
Natural gas and oil production	(7,740)	–	–
Construction materials and mining	151	–	–
Independent power production and other	–	–	–
Total cumulative effect of accounting change	$ (7,589)	$ –	$ –
Earnings on common stock:			
Electric	$ 16,950	$ 15,780	$ 18,717
Natural gas distribution	3,869	3,587	677
Utility services	6,170	6,371	12,910
Pipeline and energy services	18,158	19,097	16,406
Natural gas and oil production	63,027	53,192	63,178
Construction materials and mining	54,412	48,702	43,199
Independent power production and other	12,021	959	–
Total earnings on common stock	$ 174,607	$ 147,688	$ 155,087
Capital expenditures:			
Electric	$ 28,537	$ 27,795	$ 14,373
Natural gas distribution	15,672	11,044	14,685
Utility services	7,820	17,242	70,232
Pipeline and energy services	93,004	21,449	51,054
Natural gas and oil production	101,698	136,424	118,719
Construction materials and mining	128,487	106,893	170,585
Independent power production and other	112,858	95,748	–
Net proceeds from sale or disposition of property	(14,439)	(16,217)	(51,641)
Total net capital expenditures	$ 473,637	$ 400,378	$ 388,007
Identifiable assets:			
Electric *(b)*	$ 327,899	$ 322,475	$ 301,982
Natural gas distribution *(b)*	234,948	208,502	217,402
Utility services	221,824	230,888	239,069
Pipeline and energy services	405,904	312,858	354,336
Natural gas and oil production	602,389	554,420	476,105
Construction materials and mining	1,248,607	1,137,697	1,035,929
Independent power production and other	263,941	148,770	–
Corporate assets *(c)*	75,080	81,311	51,155
Total identifiable assets	$3,380,592	$2,996,921	$2,675,978
Property, plant and equipment:			
Electric *(b)*	$ 639,893	$ 619,230	$ 597,080
Natural gas distribution *(b)*	252,591	244,930	235,771
Utility services	76,871	70,660	59,190
Pipeline and energy services	461,793	372,420	369,775
Natural gas and oil production	871,357	755,788	630,826
Construction materials and mining	893,980	804,255	711,410
Independent power production and other	201,134	94,525	–
Less accumulated depreciation, depletion and amortization	1,175,326	1,019,438	889,816
Net property, plant and equipment	$2,222,293	$1,942,370	$1,714,236

(a) In accordance with the provision of SFAS No. 71, intercompany coal sales of $5,016 in 2001 were not eliminated.

(b) Includes allocations of common utility property.

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

Earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from utility services, natural gas and oil production, construction materials and mining, and independent power production and other are all from nonregulated operations. Capital expenditures for 2003, 2002 and 2001, related to acquisitions, in the preceding table included the following noncash transactions: issuance of the Company's equity securities of $42.4 million, $47.2 million and $57.4 million in 2003, 2002 and 2001, respectively.

NOTE 15 ACQUISITIONS

In 2003, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Montana, North Dakota and Texas and a wind-powered electric generation facility in California. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired in 2002, including the Company's common stock and cash, was $175.0 million.

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.

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 based in Colorado with related oil and gas leases and properties in Montana and Wyoming. 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 2003. 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 16
EMPLOYEE BENEFIT PLANS

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. These financial statements and this Note do not reflect the effects of the 2003 Medicare Act on the postretirement benefit plans. For more information on the 2003 Medicare Act, see new accounting standards in Note 1. 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	
	2003	2002	**2003**	2002
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$224,766**	$204,046	**$ 74,917**	$ 67,019
Service cost	**5,897**	5,135	**1,857**	1,460
Interest cost	**15,211**	14,877	**5,281**	4,915
Plan participants' contributions	**–**	–	**977**	834
Amendments	**210**	372	**754**	–
Actuarial loss	**27,701**	12,324	**10,338**	5,678
Benefits paid	**(12,450)**	(11,988)	**(5,743)**	(4,989)
Benefit obligation at end of year	**261,335**	224,766	**88,381**	74,917
Change in plan assets:				
Fair value of plan assets at beginning of year	**189,143**	224,667	**40,889**	45,175
Actual gain (loss) on plan assets	**43,087**	(26,543)	**6,148**	(4,196)
Employer contribution	**3,263**	3,007	**4,963**	4,065
Plan participants' contributions	**–**	–	**977**	834
Benefits paid	**(12,450)**	(11,988)	**(5,743)**	(4,989)
Fair value of plan assets at end of year	**223,043**	189,143	**47,234**	40,889
Funded status – over (under)	**(38,292)**	(35,623)	**(41,147)**	(34,028)
Unrecognized actuarial loss	**41,422**	35,662	**11,862**	3,484
Unrecognized prior service cost	**8,556**	9,501	**706**	–
Unrecognized net transition obligation (asset)	**(297)**	(1,247)	**19,362**	21,513
Prepaid (accrued) benefit cost	**$ 11,389**	$ 8,293	**$ (9,217)**	$ (9,031)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	**$ 19,671**	$ 16,175	**$ 614**	$ 780
Accrued benefit liability	**(8,282)**	(7,882)	**(9,831)**	(9,811)
Additional minimum liability	**–**	(4,905)	**–**	–
Intangible asset	**–**	533	**–**	–
Accumulated other comprehensive loss	**–**	4,372	**–**	–
Net amount recognized	**$ 11,389**	$ 8,293	**$ (9,217)**	$ (9,031)

Employer contributions and benefits paid in the above table include only those amounts contributed directly to, or paid directly from, plan assets.

The accumulated benefit obligation for the defined benefit pension plans reflected above was $212.0 million and $186.4 million at December 31, 2003 and 2002, respectively.

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 at December 31, 2003, were as follows:

	2003	2002
	(In thousands)	
Projected benefit obligation	**$38,845**	$32,768
Accumulated benefit obligation	**$28,840**	$24,656
Fair value of plan assets	**$24,508**	$20,615

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

	Pension Benefits			Other Postretirement Benefits		
Years ended December 31,	**2003**	2002	2001	**2003**	2002	2001
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	**$ 5,897**	$ 5,135	$ 4,716	**$ 1,857**	$ 1,460	$ 1,376
Interest cost	**15,211**	14,877	14,498	**5,281**	4,915	4,691
Expected return on assets	**(20,730)**	(21,110)	(20,672)	**(3,933)**	(3,843)	(3,619)
Amortization of prior service cost	**1,156**	1,148	1,247	**48**	–	–
Recognized net actuarial gain	**(417)**	(1,855)	(2,687)	**(255)**	(566)	(930)
Settlement (gain) loss	**–**	–	(884)	**–**	–	15
Amortization of net transition obligation (asset)	**(950)**	(947)	(965)	**2,151**	2,151	2,227
Net periodic benefit cost (income)	**167**	(2,752)	(4,747)	**5,149**	4,117	3,760
Less amount capitalized	**14**	(352)	(391)	**601**	404	329
Net periodic benefit cost (income)	**$ 153**	$ (2,400)	$ (4,356)	**$ 4,548**	$ 3,713	$ 3,431

Weighted average assumptions used to determine benefit obligations at December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
Discount rate	**6.00%**	6.75%	**6.00%**	6.75%
Rate of compensation increase	**4.70%**	4.50%	**4.50%**	4.50%

Weighted average assumptions used to determine net periodic benefit cost for the years ended December 31 were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2003	2002	**2003**	2002
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%

The expected rate of return on plan assets is based on the targeted asset allocation of 70 percent equity securities and 30 percent fixed income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

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

	2003	2002
Health care trend rate assumed for next year	**6.0%–9.5%**	6.0%–11.0%
Health care cost trend rate – ultimate	**5.0%–6.0%**	5.0%–6.0%
Year in which ultimate trend rate achieved	**1999–2012**	1999–2011

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.

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 had the following effects at December 31, 2003:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 250	$ (972)
Effect on postretirement benefit obligation	$3,479	$(9,554)

The Company's defined benefit pension plans asset allocation at December 31, 2003 and 2002, and weighted average targeted asset allocations at December 31, 2003, were as follows:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	**2003**	2002	**2003**
Equity securities	**72%**	56%	**70%**
Fixed income securities	**25**	40	**30***
Other	**3**	4	**–**
Total	**100%**	100%	**100%**

**Includes target for both fixed income securities and other.*

The Company's pension assets are managed by nine outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed income securities and equity securities. The guidelines prohibit investment in commodities and future contracts, equity private placement, employer securities and leveraged or derivative securities. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

NOTE 16 (CONTINUED)

The Company's other postretirement benefit plans asset allocation at December 31, 2003 and 2002, and weighted average targeted asset allocation at December 31, 2003, were as follows:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	**2003**	2002	**2003**
Equity securities	**66%**	50%	**70%**
Fixed income securities	**30**	45	**30***
Other	**4**	5	**–**
Total	**100%**	100%	**100%**

** Includes target for both fixed income securities and other.*

The Company expects to contribute approximately $1.6 million to its defined benefit pension plans and approximately $5.0 million to its postretirement benefit plans in 2004.

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 $27.2 million, $27.8 million and $19.9 million in 2003, 2002 and 2001, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of Note 16, 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 $5.3 million, $5.1 million and $4.3 million in 2003, 2002 and 2001, respectively. The total projected obligation for this plan was $51.1 million and $40.5 million at December 31, 2003 and 2002, respectively. The accumulated benefit obligation for this plan was $40.7 million and $33.3 million at December 31, 2003 and 2002, respectively. The additional minimum liability relating to this plan was $8.2 million and $4.0 million at December 31, 2003 and 2002, respectively. The Company has a related intangible asset recognized as of December 31, 2003 and 2002, of $1.0 million and $1.1 million, respectively. A discount rate of 6.0 percent and 6.75 percent at December 31, 2003 and 2002, respectively, and a rate of compensation increase of 4.75 percent and 4.50 percent at December 31, 2003 and 2002, respectively, were used to determine benefit obligations.

A discount rate of 6.75 percent and 7.25 percent at December 31, 2003 and 2002, respectively, and a rate of compensation increase of 4.50 percent and 5.00 percent at December 31, 2003 and 2002, respectively, were used to determine net periodic benefit cost. The increase in minimum liability included in other comprehensive income was $2.6 million in 2003 and $1.8 million in 2002.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $9.8 million in 2003, $9.6 million in 2002 and $7.2 million in 2001. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 17 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:

	2003	2002
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 52,154**	$ 53,018
Less accumulated depreciation	**34,993**	34,456
	$ 17,161	$ 18,562
Coyote Station:		
Utility plant in service	**$124,086**	$122,476
Less accumulated depreciation	**72,850**	70,778
	$ 51,236	$ 51,698

NOTE 18 REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

On May 30, 2003, Montana-Dakota Utilities Co. (Montana-Dakota), a public utility division of MDU Resources, *filed an application with the North Dakota Public Service Commission (NDPSC) for an electric rate increase.* Montana-Dakota requested a total of $7.8 million annually or 9.1 percent above current rates. On July 23, 2003, Montana-Dakota and the NDPSC Staff filed a Settlement Agreement with the NDPSC agreeing on the issues of rate of return, capital structure and cost of capital components. On October 22, 2003, the NDPSC approved the Settlement Agreement. On November 19, 2003, Montana-Dakota and the NDPSC Staff filed an additional Settlement Agreement to resolve all remaining outstanding issues with the NDPSC. This Settlement Agreement reflected an increase of $1.0 million annually and a sharing mechanism between Montana-Dakota and retail customers of wholesale electric sales margins. On December 18, 2003, the NDPSC approved the November 2003 Settlement Agreement and required Montana-Dakota to file a compliance filing with the NDPSC. On January 14, 2004, the NDPSC approved Montana-Dakota's compliance filing, which was filed on January 7, 2004, with rates effective with service rendered on and after January 23, 2004.

In December 2002, Montana-Dakota 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. On October 27, 2003, Montana-Dakota and the SDPUC Staff filed a Settlement Stipulation with the SDPUC agreeing to an increase of $1.3 million annually. On December 2, 2003, the SDPUC approved the Settlement Stipulation effective with service rendered on and after December 2, 2003.

In October 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. In December 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 issued a final order. On October 9, 2003, the MPUC issued a Final Order authorizing an increase of $1.1 million annually and requiring Great Plains to file a compliance filing with the MPUC. On January 16, 2004, the MPUC issued an Order accepting Great Plains' compliance filing, which was filed on November 10, 2003, effective with service rendered on and after January 16, 2004.

NOTE 18 (CONTINUED)

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.

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 (ALJ) issued an Initial Decision on Williston Basin's natural gas rate change application. The Initial Decision addressed numerous issues relating to the rate change application, including matters relating to allowable levels of rate base, return on common equity, and cost of service, as well as volumes established for purposes of cost recovery, and cost allocation and rate design. On July 3, 2003, the FERC issued its Order on Initial Decision. The Order on Initial Decision affirmed the ALJ's Initial Decision on many of the issues including rate base and certain cost of service items as well as volumes to be used for purposes of cost recovery, and cost allocation and rate design. However, there are other issues as to which the FERC differed with the ALJ including return on common equity and the correct level of corporate overhead expense. On August 4, 2003, Williston Basin requested a rehearing of a number of issues including determinations associated with cost of service, throughput, and cost allocation and rate design, as discussed in the FERC's Order on Initial Decision. On September 3, 2003, the FERC issued an Order granting Williston Basin's request for rehearing of the July 3, 2003, Order on Initial Decision. The Company is awaiting a decision from the FERC on the merits of the Company's rehearing request and is unable to predict the timing of the FERC's decision.

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 believes that such reserves are adequate based on its assessment of the ultimate outcome of the proceeding.

NOTE 19 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 June 1997, Jack J. Grynberg (Grynberg) filed a Federal False Claims Act suit against Williston Basin and Montana-Dakota and filed over 70 similar suits against natural gas transmission companies and producers, gatherers, and processors of natural gas. 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 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.

The matter is currently in the discovery stage. Grynberg has not specified the amount he seeks to recover. Williston Basin and Montana-Dakota are unable to estimate their potential exposure and will be unable to do so until discovery is completed. Williston Basin and Montana-Dakota believe that the Grynberg case will ultimately be dismissed because Grynberg is not, as is required by the Federal False Claims Act, the original source of the information underlying the action. Failing this, Williston Basin and Montana-Dakota believe Grynberg will not recover damages from Williston Basin and Montana-Dakota because insufficient facts exist to support the allegations.

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

Fidelity has been named as a defendant in, and/or certain of its operations are the subject of, 11 lawsuits filed in connection with its coalbed natural gas development in the Powder River Basin in Montana and Wyoming. These lawsuits were filed in federal and state courts in Montana between June 2000 and December 2003 by a number of environmental organizations, including the Northern Plains Resource Council and the Montana Environmental Information Center as well as the Tongue River Water Users' Association and the Northern Cheyenne Tribe. Two of the lawsuits have been transferred to Federal District Court in Wyoming. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Federal Clean Water Act and the National Environmental Policy Act. The lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity is unable to quantify the damages sought, and will be unable to do so until after completion of discovery. Fidelity is vigorously defending all coalbed-related lawsuits in which it is involved. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material effect on Fidelity's existing coalbed natural gas operations and/or the future development of its coalbed natural gas properties.

Montana-Dakota has joined with two electric generators in appealing a finding by the North Dakota Department of Health (Department) in September 2003 that the Department may unilaterally revise operating permits previously issued to electric generating plants. Although it is doubtful that any revision of Montana-Dakota's operating permits by the Department would reduce the amount of electricity its plants could generate, the finding, if allowed to stand, could increase costs for sulfur dioxide removal and/or limit Montana-Dakota's ability to modify or expand operations at its North Dakota generation sites. Montana-Dakota and the other electric generators filed their appeal of the order on October 8, 2003, in the Burleigh County District Court in Bismarck, North Dakota. Proceedings have been stayed pending discussions with the United States Environmental Protection Agency (EPA), the Department and the other electric generators.

In a related case, the Dakota Resource Council filed an action in Federal District Court in Denver, Colorado, on September 30, 2003, to require the EPA to enforce certain air quality standards in North Dakota. If successful, the action could require the curtailment of discharges of sulfur dioxide into the atmosphere by existing electric generating facilities and could preclude or hinder the construction of future generating facilities in North Dakota. The Company has filed a Motion to Intervene in the lawsuit and has joined in a brief supporting a Motion to Dismiss filed by the EPA.

The Company cannot predict the outcome of the Department or Dakota Resource Council matters or their ultimate impact on its operations.

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 EPA as a Potentially Responsible Party in connection with the cleanup of a commercial property site, acquired by MBI in 1999, 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. To date, costs of the overall remedial investigation of the harbor site for both the EPA and the Oregon State Department of Environmental Quality (DEQ) are being recorded, and initially paid, through an administrative consent order by the Lower Willamette Group (LWG), a group of 10 entities that does not include MBI. The LWG estimates the overall remedial investigation and feasibility study will cost approximately $10 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study has been completed, the EPA has decided on a strategy, and a record of decision has been published. While the remedial investigation and feasibility study for the harbor site has commenced, it is expected to take several years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2006, after which a cleanup plan will be undertaken.

NOTE 19
(CONTINUED)

Based upon a review of the Portland Harbor sediment contamination evaluation by the DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific West, Inc., the seller of the commercial property site to MBI, that it intends to seek indemnity for any and all liabilities incurred in relation to the above matters, 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, 2003, were $18.1 million in 2004, $12.4 million in 2005, $8.7 million in 2006, $5.1 million in 2007, $3.9 million in 2008 and $22.1 million thereafter. Rent expense was approximately $27.2 million, $26.9 million and $31.5 million for the years ended December 31, 2003, 2002 and 2001, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation, construction materials supply and electric generation construction contracts. These commitments range from one to 21 years. The commitments under these contracts as of December 31, 2003, were $167.2 million in 2004, $67.2 million in 2005, $50.1 million in 2006, $31.0 million in 2007, $30.9 million in 2008 and $146.3 million thereafter. Amounts purchased under these various commitments for the years ended December 31, 2003, 2002 and 2001, were approximately $204.6 million, $152.1 million and $193.0 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

Guarantees

Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX in connection with the Company's equity method investment in the natural gas-fired electric generating facility in Brazil, as discussed in Note 2. The Company, through MDU Brasil, owns 49 percent of MPX. The main business purpose of Centennial extending the guarantee to MPX's creditors is to enable MPX to obtain lower borrowing costs. At December 31, 2003, the aggregate amount of borrowings outstanding subject to these guarantees was $45.5 million and the scheduled repayment of these borrowings is $11.0 million in 2004, $10.7 million in 2005, $10.7 million in 2006, $10.7 million in 2007 and $2.4 million in 2008. The individual investor (who through EBX Empreendimentos Ltda. (EBX), a Brazilian company, owns 51 percent of MPX) has also guaranteed a portion of these loans. In the event MPX defaults under its obligation, Centennial and the individual investor would be required to make payments under their guarantees. Centennial and the individual investor have entered into reimbursement agreements under which they have agreed to reimburse each other to the extent they may be required to make any guarantee payments in excess of their proportionate ownership share in MPX. These guarantees are not reflected on the Consolidated Balance Sheets.

In addition, WBI Holdings, Inc. (WBI Holdings), an indirect wholly owned subsidiary of the Company, has guaranteed certain of its subsidiary's natural gas and oil price swap and collar agreement obligations. The amount of the subsidiary's obligations at December 31, 2003, was $1.8 million. There is no fixed maximum amount guaranteed in relation to the natural gas and oil price swap and collar agreements, as the amount of the obligation is dependent upon natural gas and oil commodity prices. 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 at December 31, 2003, expire in 2004; however, the subsidiary continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. At December 31, 2003, the amount outstanding was reflected on the Consolidated Balance Sheets. In the event the above subsidiary defaults under its obligations, WBI Holdings would be required to make payments under its 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, insurance policies and certain other guarantees. At December 31, 2003, the fixed maximum amounts guaranteed under these agreements aggregated $46.4 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $20.1 million in 2004; $5.9 million in 2005; $3.5 million in 2006; $500,000 in 2007; $900,000 in 2009; $12.0 million in 2012; $500,000, which is subject to expiration 30 days after the receipt of written notice and $3.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $372,000 and was reflected on the Consolidated Balance Sheets at December 31, 2003. 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 guarantee.

Fidelity and WBI Holdings have outstanding guarantees to Williston Basin. These guarantees are related to natural gas transportation and storage agreements that guarantee the performance of Prairielands Energy Marketing, Inc. (Prairielands), an indirect wholly owned subsidiary of the Company. At December 31, 2003, the fixed maximum amounts guaranteed under these agreements aggregated $22.9 million. Scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $2.9 million in 2005 and $20.0 million in 2009. In the event of Prairielands' default in its payment obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee. The amount outstanding by Prairielands under the above guarantees was $837,000, which was not reflected on the Consolidated Balance Sheets at December 31, 2003, because these intercompany transactions are eliminated in consolidation.

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 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 these maintenance items were reflected on the Consolidated Balance Sheets at December 31, 2003.

As of December 31, 2003, Centennial was contingently liable for the performance of certain of its subsidiaries under approximately $360 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. The purpose of Centennial's indemnification is to allow the subsidiaries to obtain bonding at competitive rates. In the event a subsidiary of the Company does not fulfill its obligations in relation to its bonded contract or obligation, Centennial may be required to make payments under its indemnification. A large portion of these contingent commitments are expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. The surety bonds were not reflected on the Consolidated Balance Sheets.

TO THE BOARD OF DIRECTORS AND STOCKHOLDERS OF MDU RESOURCES GROUP, INC.:

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. (the "Company") as of December 31, 2003 and 2002, and the related consolidated statements of income, common stockholders' equity, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. The consolidated financial statements of the Company for the year ended December 31, 2001, before the adjustments described in Note 11, additional transitional disclosures described in Notes 3 and 9, and the reclassifications to the consolidated financial statements described in Note 1, were audited by other auditors who have ceased operations. Those auditors expressed an unqualified opinion on those consolidated financial statements in their report dated January 23, 2002.

We conducted our audits 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 consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated 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 2003 and 2002 consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed above, the consolidated financial statements of the Company for the year ended December 31, 2001 were audited by other auditors who have ceased operations. As described in Note 11, those consolidated financial statements have been revised to give effect to the stock split on October 29, 2003. We audited the adjustments described in Note 11 that were applied to revise the 2001 consolidated financial statements for such stock split. Our audit procedures included (1) comparing the amounts shown in the earnings per share disclosures for 2001 to the Company's underlying accounting analysis obtained from management, (2) comparing the previously reported shares outstanding and income statement amounts per the Company's accounting analysis to the previously issued consolidated financial statements, and (3) recalculating the additional shares to give effect to the stock split and testing the mathematical accuracy of the underlying analysis. Also, as described in Note 3, these consolidated financial statements have been revised to include the transitional disclosures required by Statement of Financial Accounting Standards ("SFAS") No. 142, *Goodwill and Other Intangible Assets*, which was adopted by the Company as of January 1, 2002. Our audit procedures, with respect to the disclosures in Note 3 with respect to the 2001 disclosures, included (a) comparing the previously reported net income to the previously issued consolidated 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 SFAS No. 142 (including any tax effects) to the Company's underlying analysis obtained from management, and (b) testing the mathematical accuracy of (i) the reconciliation of adjusted net income to reported net income and (ii) the related earnings per share amounts. Also, as described in Note 1, these consolidated financial statements have been reclassified to include additional disclosures relating to the components comprising operating revenues and operation and maintenance expenses. Our audit procedures with respect to 2001 as it relates to the reclassifications described in Note 1 included (1) comparing the previously reported operating revenues and operation and maintenance expenses to previously issued consolidated financial statements, (2) comparing the operating revenues and operation and maintenance expenses to the Company's underlying analysis obtained from management, and (3) testing the mathematical accuracy of the underlying analysis. Also, as described in Note 9, these consolidated financial statements have been revised to include disclosures required by SFAS No. 143, *Accounting for Asset Retirement Obligations*, which was adopted by the Company as of January 1, 2003. Our audit procedures with respect to the disclosures in Note 9 as they relate to 2001 included testing the mathematical accuracy of the underlying analysis. In our opinion, the 2001 adjustments for the stock split described in Note 11 have been properly applied, the goodwill disclosures for 2001 in Note 3 and the asset retirement disclosures for 2001 in Note 9 are appropriate, and the reclassifications to the consolidated financial statements described in Note 1 have been properly applied. However, we were not engaged to audit, review, or apply any procedures to the 2001 consolidated financial statements of the Company other than with respect to such adjustments, reclassifications, and disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2001 consolidated financial statements taken as a whole.

As discussed in Notes 1 and 9 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations; and as discussed in Notes 1 and 3 to the consolidated financial statements, effective January 1, 2002, the Company changed its method of accounting for goodwill.

DELOITTE & TOUCHE LLP

Minneapolis, Minnesota
February 17, 2004

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.

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 2003 and 2002:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2003				
Operating revenues	**$467,753**	**$548,219**	**$716,099**	**$620,118**
Operating expenses	**414,806**	**473,534**	**600,433**	**551,344**
Operating income	**52,947**	**74,685**	**115,666**	**68,774**
Income before cumulative effect of accounting change	**27,697**	**43,473**	**65,521**	**46,222**
Cumulative effect of accounting change	**(7,589)**	**–**	**–**	**–**
Net income	**20,108**	**43,473**	**65,521**	**46,222**
Earnings per common share – basic:				
Earnings before cumulative effect of accounting change	**.25**	**.39**	**.58**	**.41**
Cumulative effect of accounting change	**(.07)**	**–**	**–**	**–**
Earnings per common share – basic	**.18**	**.39**	**.58**	**.41**
Earnings per common share – diluted:				
Earnings before cumulative effect of accounting change	**.25**	**.39**	**.58**	**.40**
Cumulative effect of accounting change	**(.07)**	**–**	**–**	**–**
Earnings per common share – diluted	**.18**	**.39**	**.58**	**.40**
Weighted average common shares outstanding:				
Basic	**110,318**	**110,602**	**112,359**	**112,618**
Diluted	**111,094**	**111,532**	**113,368**	**113,804**
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	.23	.23	.51	.42
Diluted	.22	.23	.50	.42
Weighted average common shares outstanding:				
Basic	104,203	105,684	106,385	108,142
Diluted	105,020	106,540	107,017	108,864
Pro forma amounts assuming retroactive application of accounting change:				
Net income	$ 23,126	$ 24,255	$ 53,332	$ 45,339
Earnings per common share – basic	.22	.23	.50	.42
Earnings per common share – diluted	.22	.23	.50	.41

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 and around the Gulf of Mexico in proportion to its ownership 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 Fidelity's proportionate share of all its natural gas and oil interests.

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

	2003	2002	2001
		(In thousands)	
Subject to amortization	**$758,500**	$603,151	$506,155
Not subject to amortization	**104,339**	145,692	122,354
Total capitalized costs	**862,839**	748,843	628,509
Less accumulated depreciation, depletion and amortization	**305,349**	239,964	195,469
Net capitalized costs	**$557,490**	$508,879	$433,040

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

Years ended December 31,	2003*	2002	2001
		(In thousands)	
Acquisitions	**$ 3,027**	$ 31,439	$ 1,695
Exploration	**19,193**	5,325	13,938
Development**	**77,583**	94,943	102,670
Total capital expenditures	**$99,803**	$131,707	$118,303

** Excludes $14,724 of additions to property, plant and equipment related to the recognition of future liabilities associated with the plugging and abandonment of natural gas and oil wells in accordance with SFAS No. 143, as discussed in Note 9.*

*** Includes expenditures for proved undeveloped reserves of $23.3 million, $10.1 million and $15.0 million for the years ended December 31, 2003, 2002 and 2001, respectively.*

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,	2003	2002*	2001
		(In thousands)	
Revenues:			
Sales to external customers	**$140,034**	$145,170	$139,939
Sales to affiliates	**124,077**	55,437	61,178
Production costs	**67,292**	52,520	44,435
Depreciation, depletion and amortization	**60,072****	48,064	41,223
Pretax income	**136,747**	100,023	115,459
Income tax expense	**51,925**	36,886	45,245
Results of operations for producing activities before cumulative effect of accounting change	**84,822**	63,137	70,214
Cumulative effect of accounting change	**(7,740)**	–	–
Results of operations for producing activities	**$ 77,082**	$ 63,137	$ 70,214

** Includes the compromise agreement as discussed in Note 19.*

*** Includes $1,356 of accretion of discount for asset retirement obligations in 2003 in accordance with SFAS No. 143, as discussed in Note 1.*

The following table summarizes the Company's estimated quantities of proved natural gas and oil reserves at December 31, 2003, 2002 and 2001, 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.

	2003		2002		2001	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
			(In thousands of Mcf/barrels)			
Proved developed and undeveloped reserves:						
Balance at beginning of year	**372,500**	**17,500**	324,100	17,500	309,800	15,100
Production	**(54,700)**	**(1,900)**	(48,200)	(2,000)	(40,600)	(2,000)
Extensions and discoveries	**113,300**	**3,300**	80,100	2,200	66,400	2,000
Purchases of proved reserves	**900**	**–**	1,200	100	1,000	100
Sales of reserves in place	**–**	**(100)**	(4,400)	(300)	–	–
Revisions of previous estimates	**(20,300)**	**100**	19,700	–	(12,500)	2,300
Balance at end of year	**411,700**	**18,900**	372,500	17,500	324,100	17,500

Proved developed reserves:		
January 1, 2001	263,400	14,200
December 31, 2001	291,300	17,100
December 31, 2002	331,300	14,800
December 31, 2003	**342,800**	**15,000**

All of the Company's interests in natural gas and oil reserves are located in the United States and in and around 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:

	2003	2002	2001
		(In thousands)	
Future cash inflows	**$2,547,400**	$1,726,000	$974,200
Future production costs	**651,300**	513,200	361,600
Future development costs	**67,100**	61,200	64,600
Future net cash flows before income taxes	**1,829,000**	1,151,600	548,000
Future income tax expense	**601,000**	324,000	112,000
Future net cash flows	**1,228,000**	827,600	436,000
10% annual discount for estimated timing of cash flows	**491,200**	321,300	174,000
Discounted future net cash flows relating to proved natural gas and oil reserves	**$ 736,800**	$ 506,300	$262,000

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

	2003	2002	2001
		(In thousands)	
Beginning of year	**$ 506,300**	$ 262,000	$ 921,300
Net revenues from production	**(220,000)**	(112,900)	(153,500)
Change in net realization	**318,600**	296,100	(1,119,700)
Extensions, discoveries and improved recovery, net of future production-related costs	**245,800**	117,000	40,200
Purchases of proved reserves	**2,800**	3,700	2,600
Sales of reserves in place	**(600)**	(8,900)	–
Changes in estimated future development costs	**(4,000)**	(1,100)	(6,700)
Development costs incurred during the current year	**35,300**	19,400	31,600
Accretion of discount	**62,400**	27,300	122,700
Net change in income taxes	**(172,000)**	(124,700)	436,500
Revisions of previous estimates	**(35,500)**	30,000	(11,700)
Other	**(2,300)**	(1,600)	(1,300)
Net change	**230,500**	244,300	(659,300)
End of year	**$ 736,800**	$ 506,300	$ 262,000

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 development costs estimated to be spent in each of the next three years to develop proved undeveloped reserves are $37.1 million in 2004, $6.7 million in 2005 and $4.4 million in 2006. 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.

	2003	2002	2001	2000	1999	1998*
Selected Financial Data						
Operating revenues (000's):						
Electric	$ 178,562	$ 162,616	$ 168,837	$ 161,621	$ 154,869	$ 147,221
Natural gas distribution	274,608	186,569	255,389	233,051	157,692	154,147
Utility services	434,177	458,660	364,750	169,382	99,917	64,232
Pipeline and energy services	252,192	165,258	531,114	636,848	383,532	180,732
Natural gas and oil production	264,358	203,595	209,831	138,316	78,394	61,842
Construction materials and mining	1,104,408	962,312	806,899	631,396	469,905	346,451
Independent power production and other	34,989	6,776	–	–	–	–
Intersegment eliminations	(191,105)	(114,249)	(113,188)	(96,943)	(64,500)	(57,998)
	$2,352,189	$2,031,537	$2,223,632	$1,873,671	$1,279,809	$ 896,627
Operating income (000's):						
Electric	$ 35,761	$ 33,915	$ 38,731	$ 38,743	$ 35,727	$ 32,167
Natural gas distribution	6,502	2,414	3,576	9,530	6,688	8,028
Utility services	12,885	13,980	25,199	16,606	11,518	5,932
Pipeline and energy services	35,155	39,091	30,368	28,782	40,627	33,651
Natural gas and oil production	118,347	85,555	103,943	66,510	26,845	(50,444)
Construction materials and mining	91,579	91,430	71,451	56,816	38,346	41,609
Independent power production and other	11,843	(268)	–	–	–	–
	$ 312,072	$ 266,117	$ 273,268	$ 216,987	$ 159,751	$ 70,943
Earnings on common stock (000's):						
Electric	$ 16,950	$ 15,780	$ 18,717	$ 17,733	$ 15,973	$ 13,908
Natural gas distribution	3,869	3,587	677	4,741	3,192	3,501
Utility services	6,170	6,371	12,910	8,607	6,505	3,272
Pipeline and energy services	18,158	19,097	16,406	10,494	20,972	18,651
Natural gas and oil production	70,767**	53,192	63,178	38,574	16,207	(30,501)
Construction materials and mining	54,261**	48,702	43,199	30,113	20,459	24,499
Independent power production and other	12,021	959	–	–	–	–
Earnings on common stock before cumulative effect of accounting change	182,196**	147,688	155,087	110,262	83,308	33,330
Cumulative effect of accounting change	(7,589)	–	–	–	–	–
	$ 174,607	$ 147,688	$ 155,087	$ 110,262	$ 83,308	$ 33,330
Earnings per common share before cumulative effect of accounting change – diluted	$ 1.62**	$ 1.38	$ 1.52	$ 1.20	$ 1.01	$ .44
Cumulative effect of accounting change	(.07)	–	–	–	–	–
	$ 1.55	$ 1.38	$ 1.52	$ 1.20	$ 1.01	$ .44
Pro forma amounts assuming retroactive application of accounting change:						
Net income (000's)	$ 182,913	$ 146,052	$ 152,933	$ 108,951	$ 82,932	$ 33,253
Earnings per common share – diluted	$ 1.62	$ 1.36	$ 1.49	$ 1.17	$ 1.00	$ .43
Common Stock Statistics						
Weighted average common shares outstanding – diluted (000's)	112,460	106,863	101,803	92,085	82,306	76,255
Dividends per common share	$ .6600	$ .6266	$ .6000	$ .5733	$ .5467	$ .5223
Book value per common share	$ 12.66	$ 11.56	$ 10.60	$ 9.03	$ 7.83	$ 6.93
Market price per common share (year-end)	$ 23.81	$ 17.21	$ 18.77	$ 21.67	$ 13.33	$ 17.54
Market price ratios:						
Dividend payout	43%	45%	39%	48%	54%	119%
Yield	2.9%	3.7%	3.3%	2.7%	4.2%	3.0%
Price/earnings ratio	15.4x	12.5x	12.3x	18.1x	13.2x	39.9x
Market value as a percent of book value	188.1%	148.8%	177.0%	239.9%	170.4%	253.2%
Profitability Indicators						
Return on average common equity	13.0%	12.5%	15.3%	14.3%	13.9%	6.5%
Return on average invested capital	8.9%	8.6%	10.1%	9.5%	9.6%	5.5%
Interest coverage	7.4x	7.7x	8.5x	8.3x	7.1x	6.1x
Fixed charges coverage, including preferred dividends	4.7x	4.8x	5.3x	4.1x	4.3x	2.5x
General						
Total assets (000's)	$3,380,592	$2,996,921	$2,675,978	$2,358,981	$1,806,648	$1,488,713
Net long-term debt (000's)	$ 939,450	$ 819,558	$ 783,709	$ 728,166	$ 563,545	$ 413,264
Redeemable preferred stock (000's)	$ –	$ 1,300	$ 1,400	$ 1,500	$ 1,600	$ 1,700
Capitalization ratios:						
Common equity	60%	60%	58%	54%	54%	56%
Preferred stocks	1	1	1	1	1	2
Long-term debt	39	39	41	45	45	42
	100%	100%	100%	100%	100%	100%

*Reflects $39.9 million or 52 cents per common share in noncash after-tax write-downs of natural gas and oil properties.
**Before cumulative effect of the change in accounting for asset retirement obligations required by the adoption of SFAS No. 143, as discussed in Notes 1 and 9.
NOTE: Common stock share amounts reflect the Company's three-for-two common stock splits effected in July 1998 and October 2003.

	2003	2002	2001	2000	1999	1998
Electric						
Retail sales (thousand kWh)	**2,359,888**	2,275,024	2,177,886	2,161,280	2,075,446	2,053,862
Sales for resale (thousand kWh)	**841,637**	784,530	898,178	930,318	943,520	586,540
Electric system summer generating and firm purchase capability – kW (Interconnected system)	**542,680**	500,570	500,820	500,420	492,800	489,100
Demand peak – kW (Interconnected system)	**470,470**	458,800	453,000	432,300	420,550	402,500
Electricity produced (thousand kWh)	**2,384,884**	2,316,980	2,469,573	2,331,188	2,350,769	2,103,199
Electricity purchased (thousand kWh)	**929,439**	857,720	792,641	948,700	860,508	730,949
Average cost of fuel and purchased power per kWh	**$.019**	$.018	$.018	$.016	$.016	$.017
Natural Gas Distribution						
Sales (Mdk)	**38,572**	39,558	36,479	36,595	30,931	32,024
Transportation (Mdk)	**13,903**	13,721	14,338	14,314	11,551	10,324
Weighted average degree days – % of previous year's actual	**96%**	109%	95%	113%	95%	94%
Pipeline and Energy Services						
Transportation (Mdk)	**90,239**	99,890	97,199	86,787	78,061	88,974
Gathering (Mdk)	**75,861**	72,692	61,136	41,717	19,799	9,093
Natural Gas and Oil Production						
Production:						
Natural gas (MMcf)	**54,727**	48,239	40,591	29,222	24,652	20,699
Oil (000's of barrels)	**1,856**	1,968	2,042	1,882	1,758	1,912
Average realized prices:						
Natural gas (per Mcf)	**$ 3.90**	$ 2.72	$ 3.78	$ 2.90	$ 1.94	$ 1.81
Oil (per barrel)	**$27.25**	$22.80	$24.59	$23.06	$15.34	$12.71
Net recoverable reserves:						
Natural gas (MMcf)	**411,700**	372,500	324,100	309,800	268,900	243,600
Oil (000's of barrels)	**18,900**	17,500	17,500	15,100	14,700	11,500
Construction Materials and Mining						
Construction materials (000's):						
Aggregates (tons sold)	**38,438**	35,078	27,565	18,315	13,981	11,054
Asphalt (tons sold)	**7,275**	7,272	6,228	3,310	2,993	1,790
Ready-mixed concrete (cubic yards sold)	**3,484**	2,902	2,542	1,696	1,186	1,021
Recoverable aggregate reserves (tons)	**1,181,400**	1,110,020	1,065,330	894,500	740,030	654,670
Coal (000's):						
Sales (tons)	**–***	–*	1,171*	3,111	3,236	3,113
Lignite deposits (tons)	**26,910***	37,761*	56,012*	145,643	182,761	190,152
Independent Power Production and Other**						
Net generation capacity – kW	**279,600**	213,000	–	–	–	–
Electricity produced and sold (thousand kWh)	**270,044**	15,804	–	–	–	–

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

***Reflects domestic independent power production operations acquired in November 2002 and January 2003.*

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, precast concrete, ready-mixed concrete, prestress 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 per share by earnings per share.

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 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.

Ex-dividend date The first day of trading on which the seller, rather than the new purchaser of stock, is entitled to the recently declared dividend.

Federal Energy Regulatory Commission 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 net earnings before taxes plus interest and certain rent expenses by interest and certain rent expenses.

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 and transportation 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 natural gas or oil field. Natural gas is injected and withdrawn as needed primarily to help meet winter heating demand.

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

Record date The date on which a shareholder must be registered as a shareholder to receive a declared dividend or vote on company matters.

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

Retained earnings Earnings not paid 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 Federal agency that regulates financial markets. It 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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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 2003 was 199,943 shares. The range of high, low and closing quarterly common stock sales prices for 2003 and 2002, as reported by the NYSE, are listed below:

	High	Low	Close
2003			
First Quarter	$18.87	$16.41	$18.61
Second Quarter	22.66	18.55	22.33
Third Quarter	23.32	20.37	22.52
Fourth Quarter	24.35	22.23	23.81
2002			
First Quarter	$20.73	$18.17	$20.67
Second Quarter	22.30	17.17	17.53
Third Quarter	18.27	12.00	15.22
Fourth Quarter	17.33	13.94	17.21

The above prices have been adjusted for the stock split effected in October 2003.

Dividend Reinvestment and Stock Purchase Plan
MDU Resources' 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.

2004 Key Dividend Dates*

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 9	March 11	April 1
Second Quarter	June 8	June 10	July 1
Third Quarter	Sept. 7	Sept. 9	Oct. 1
Fourth Quarter	Dec. 7	Dec. 9	Jan. 1, 2005

*Subject to discretion of the Board of Directors

Internet Account Access
Registered shareholders have electronic access to their 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 interested in information about MDU Resources should call **Arlene Stillwell** in the Investor Relations Department at **(800) 437-8000, ext. 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. CDT, Tuesday, April 27, 2004, at the Montana-Dakota Utilities Co. Service Center, 909 Airport Road, Bismarck, N.D.

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 and Senior Notes
The Bank of New York
Corporate Trust Department
101 Barclay St. – 12W
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, 2003, 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 the company's 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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WBI Holdings
West Hawaii Concrete
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Young Contractors

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