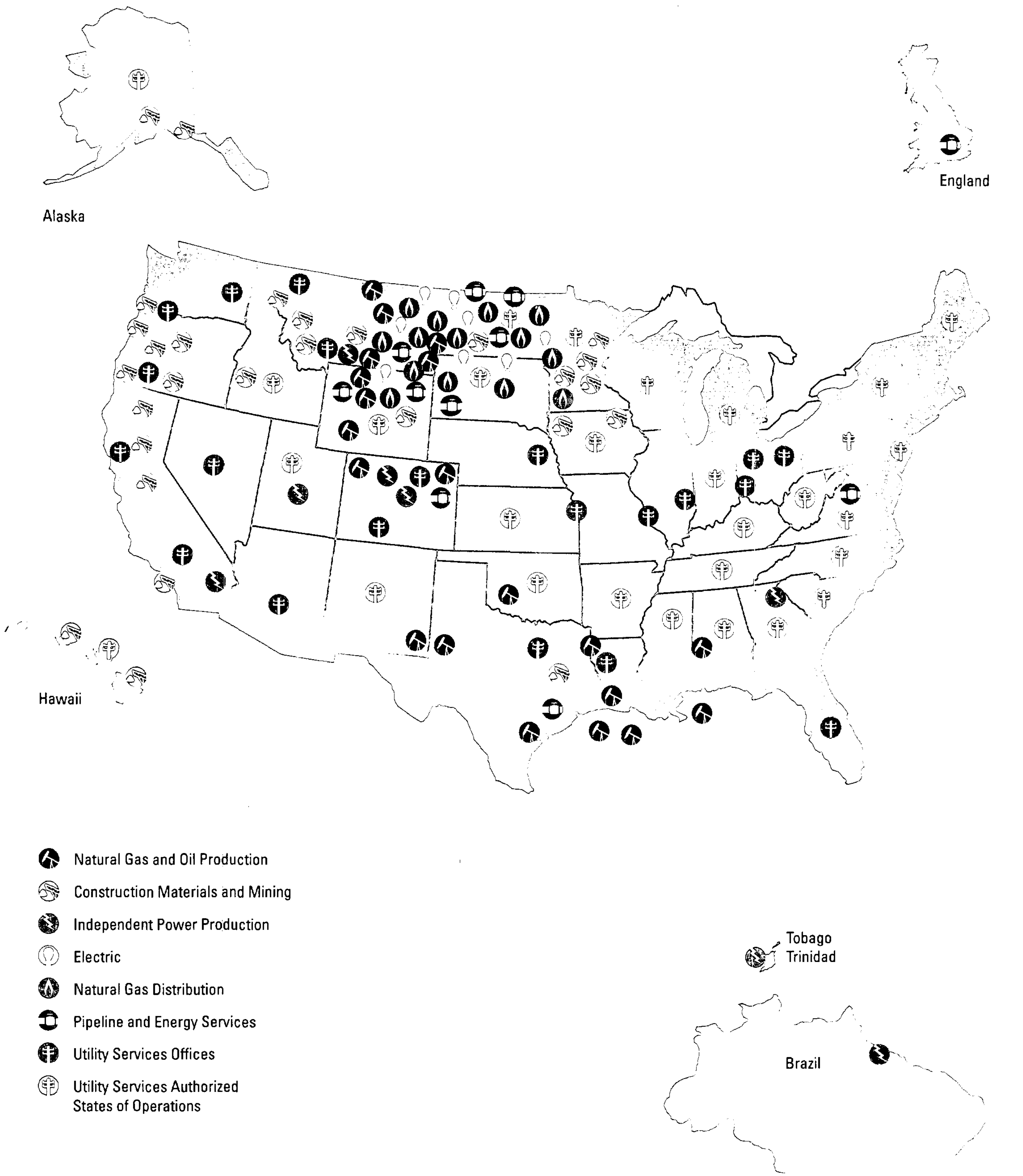
BUILDING A STRONG AMERICA

The Journey Continues

2004 ANNUAL REPORT

Our Operations



NATURAL GAS AND OIL PRODUCTION

Revenues (*millions*)	$342.9
Earnings (*millions*)	$110.8
Production	
Natural gas (*Bcf*)	59.8
Oil (*million barrels*)	1.7
Proved reserves	
Natural gas (*Bcf*)	453.2
Oil (*million barrels*)	17.1
Corporate earnings contribution	54%

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

Independent natural gas and oil companies such as Chesapeake Energy Corporation, Comstock Resources, EnCana, Encore Acquisition, Meridian Resources, Newfield Exploration, Noble Energy, St. Mary Land & Exploration, Stone Energy, Swift Energy, Unit Corporation and XTO

CONSTRUCTION MATERIALS AND MINING

Revenues (*millions*)	$1,322.2
Earnings (*millions*)	$50.7
Sales (*millions*)	
Aggregates (*tons*)	43.4
Asphalt (*tons*)	8.6
Ready-mixed concrete (*cubic yards*)	4.3
Recoverable aggregate reserves (*billion tons*)	1.3
Corporate earnings contribution	25%

- Federal, state and local governments
- General and commercial contractors
- Residential and commercial developers
- Home builders
- General public

Other construction materials companies such as Ashland, Cemex, CRH (Oldcastle), Eagle Materials, Florida Rock Industries, Hanson Building Materials, Holcim, LaFarge North America, Martin Marietta Materials, Rinker Group, TXI, Trinity Industries, U.S. Concrete and Vulcan Materials

INDEPENDENT POWER PRODUCTION

Revenues (*millions*)	$43.1
Earnings (*millions*)	$26.3
Electricity produced and sold* (*million kWh*)	204.4
Corporate earnings contribution	13%

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

Other independent power producers that operate power plants under contract to nonaffiliated utilities including American Electric Power, Calpine, CMS Energy, Dominion, Duke Energy and PPL

ELECTRIC AND NATURAL GAS DISTRIBUTION

Revenues (*millions*)	
Electric	$178.8
Natural gas distribution	$316.1
Earnings (*millions*)	
Electric	$12.8
Natural gas distribution	$2.2
Electric sales (*million kWh*)	
Retail	2,303.5
Sales for resale	821.5
Natural gas distribution (*MMdk*)	
Sales	36.6
Transportation	13.9
Corporate earnings contribution	
Electric	6%
Natural gas distribution	1%

- **Electric customers**

Residential	97,368
Commercial	18,371
Industrial and other	1,994
Electric suppliers in the Upper Midwest are wholesale customers	

- **Natural gas customers**

Residential	219,143
Commercial	28,069
Industrial	111

Other energy providers, including propane and fuel oil dealers, electric utilities, rural electric cooperatives and other electric and natural gas utilities such as Allete, Alliant Energy, Black Hills Corporation, Cascade Natural Gas, DPL, IDACORP, NorthWestern Energy, Otter Tail Power, Peoples Energy, Puget Energy, The Laclede Group and Xcel Energy

PIPELINE AND ENERGY SERVICES

Revenues (*millions*)	$357.2
Earnings (*millions*)	$8.9
Pipeline (*MMdk*)	
Transportation	114.2
Gathering	80.5
Corporate earnings contribution	4%

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

Other natural gas pipeline and gathering companies such as Bear Paw Energy, Colorado Interstate Gas, Kinder Morgan, National Fuel Gas, Northern Border Partners, ONEOK, Questar, Thunder Creek Gas Services and Western Gas Resources

UTILITY SERVICES

Revenues (*millions*)	$426.8
Loss (*millions*)	$(5.6)
Corporate earnings contribution	(3)%

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

Other utility services contractors such as Dycom Industries, EMCO, Exelon, InfraSource, Integrated Electric Services, MasTec, MYR Group, Quanta Services and other industrial and commercial electrical contractors

** Excludes equity method investments.*

NOTE: The corporation also had revenues from other miscellaneous operations totaling $4.4 million, which resulted in earnings of $.3 million. Consolidated revenues reflect intersegment eliminations of $272.2 million.

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ON THE COVER

COMPANY DESCRIPTION

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 Part I and Part II, Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations – Risk Factors and Cautionary Statements that May Affect Future Results of the company's 2004 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.

The Journey Continues

Determined explorers with a mission completed a legendary journey. Talented employees sharing a vision are building a great company. For more than 80 years, MDU Resources has grown along and beyond the Lewis and Clark Trail. Like the famed explorers, our expertise and innovative spirit lead our success as we help build a strong America. Our goal is to become legendary to our stakeholders. The journey continues.

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

Highlights

YEARS ENDED DECEMBER 31,	2004	2003	INCREASE/DECREASE AMOUNT	PERCENT
	(In millions, where applicable)			
Operating revenues	$2,719.3	$2,352.2	$367.1	16
Operating income	$ 320.7	$ 312.1	$ 8.6	3
Earnings on common stock:				
Earnings before cumulative effect of accounting change	$ 206.4	$ 182.2*	$ 24.2	13
Cumulative effect of accounting change	–	(7.6)	7.6	–
Earnings on common stock	$ 206.4	$ 174.6	$ 31.8	18
Earnings per common share – basic:				
Earnings before cumulative effect of accounting change	$ 1.77	$ 1.64*	$ .13	8
Cumulative effect of accounting change	–	(.07)	.07	–
Earnings per common share – basic	$ 1.77	$ 1.57	$ .20	13
Earnings per common share – diluted:				
Earnings before cumulative effect of accounting change	$ 1.76	$ 1.62*	$ .14	9
Cumulative effect of accounting change	–	(.07)	.07	–
Earnings per common share – diluted	$ 1.76	$ 1.55	$ .21	14
Dividends per common share	$ .70	$ .66	$ .04	6
Weighted average common shares outstanding – diluted	117.4	112.5	4.9	4
Total assets	$3,733.5	$3,380.6	$352.9	10
Total equity	$1,681.0	$1,450.6	$230.4	16
Long-term debt (net of current maturities)	$ 873.4	$ 939.5	$ (66.1)	(7)
Capitalization ratios:				
Common equity	65%	60%		
Preferred stocks	1	1		
Long-term debt (net of current maturities)	34	39		
	100%	100%		
Return on average common equity	13.2%	13.0%		
Price/earnings ratio	15.2x	15.4x		
Book value per common share	$ 14.09	$ 12.66		
Market value as a percent of book value	189.4%	188.1%		
Full-time employees	8,058	7,797		

** 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.

Achieved record earnings of $206.4 million.

Grew revenues by 16 percent.

Lowered consolidated debt ratio to 34 percent.

Increased dividends for 14th consecutive year.

Named to Forbes Platinum 400 list for fifth year.

Two hundred years ago, Meriwether Lewis and William Clark spent the winter in what is now North Dakota – about 40 miles north of our present-day corporate office. Their journey was built on President Thomas Jefferson's vision of coast-to-coast commerce and learning about natural resources that would fuel the country's growth.

Our corporation is built on our vision statement. We have grown from a small utility with roots in the Northern Great Plains to an international enterprise. Our mission is to provide value-added natural resource products and services that exceed customer expectations.

Lewis and Clark certainly exceeded Jefferson's expectations. Throughout this report, you will see excerpts from their fascinating journals. My letter is like their journals – a story documenting a successful mission to help build a strong America, made possible by people with determination and a vision.

Record results benefit shareholders

MDU Resources had another exceptional year. In 2004, we had record earnings of $206.4 million, compared to $174.6 million for 2003. Earnings per common share, diluted, totaled $1.76, compared to $1.55 for 2003.

To our shareholders that means an outstanding one-year total shareholder return of 15 percent. Over the past five years, our total annual return was 19 percent, while our peer group average return was 16 percent and the S&P 500 average return was -2 percent.

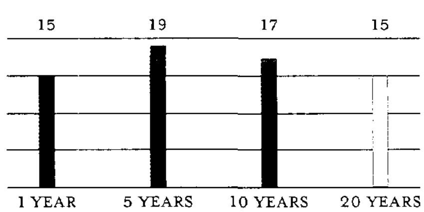
Our dividend is an important aspect of shareholder returns. MDU Resources has an unbroken record of quarterly dividend payments since 1937. We increased our quarterly dividend 5.9 percent in August 2004. This increased our annualized dividend to 72 cents per share. Our dividend has gone up every year since 1990. In addition, the compound annual growth rate for our annual dividends has exceeded 5 percent over the past five years.

Company recognized for performance

We were named a Mergent Dividend Achiever in 2004 for our outstanding record of 10 or more years of consecutive dividend increases. We're proud of this honor, especially because only 3 percent of dividend-paying companies in the United States have achieved it.

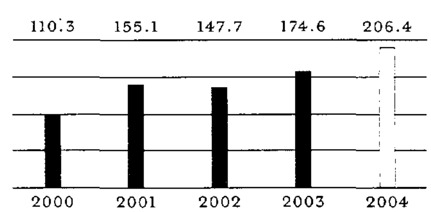
The April 5, 2004, issue of Fortune Magazine ranked MDU Resources No. 629 in its Fortune 1,000 list, based on total revenues. Out of 18 companies listed in the energy industry, MDU Resources was ranked No. 2 both for total return to investors and for earnings per share annual growth from 1993 to 2003. Total return during that period was 14 percent and earnings per share annual growth was 9 percent.

ANNUAL STOCKHOLDER RETURN
(Percent)



Stock price appreciation and increasing dividends benefit stockholders.

EARNINGS
(Dollars in millions)



Earnings reflect the company's successful growth strategy.

For the fifth consecutive year, Forbes magazine named MDU Resources to its Platinum 400 list of the best big companies in America, based on criteria such as corporate governance and accounting practices as well as financial performance. The list appeared in the January 10, 2005, issue.

With integrity

The first two words of our vision statement are "with integrity." You will read more about this in the corporate governance section. Operating with integrity is core to our culture at MDU Resources. It guides every decision we make.

Related to that is our commitment to respect the environment and to support the communities we serve. Our natural gas and oil segment was recognized with a major environmental stewardship award in 2004, as well as a public outreach and education award for its work with landowners. The MDU Resources Foundation, the philanthropic organization within the corporation and its affiliated companies, has contributed more than $8 million to qualified charities and organizations throughout the United States since its incorporation in 1983.

Creating superior shareholder value

Nothing demonstrates the next part of our vision statement, "creating superior shareholder value," like the performance of our natural gas and oil business in 2004. Natural gas prices were 20 percent higher and oil prices were 25 percent higher. While prices certainly contributed to the $110.8 million in earnings from that segment in 2004, the strategies behind those earnings allowed us to fully seize the advantages of a strong market.

We are focused on building long-term value by increasing the natural gas and oil reserves that we own and the production that we operate. Our nonoperated investments diversify our reserve portfolio and our cash flow. We have doubled our production levels from 35 billion cubic feet equivalent in 1999 to 70 Bcfe in 2004. During that same time period, reserves also grew by 9 percent on a compound annual growth basis. We had positive results for 91 percent of the wells we drilled last year and increased total production by 7 percent from 2003 levels. Success such as this points to the expertise of our employees. If you put that all together – a vertically integrated company with a diverse asset base, growth in production as well as reserves and a team of talented employees – our shareholders are getting good value for their investments.

Expanding upon our expertise

The next part of our vision statement, "expanding upon our expertise," is best demonstrated by our construction materials and mining segment. We applied our coal mining expertise to the aggregate industry to start this business in 1992. It has achieved phenomenal growth since that time, now representing 25 percent of the corporation's earnings. We've acquired more than 50 companies in medium-size markets near metropolitan growth areas. This strategy has proved successful in obtaining market share and in integrating these companies into our culture. We have 1.3 billion tons of aggregate reserves, a valuable asset in a country that consumes more than 10 tons of aggregate reserves per capita on an annual basis.

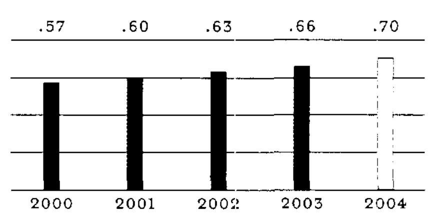
Another example of expanding on our expertise is our domestic and international independent power production segment. We've been operating power plants since the company began more than 80 years ago. We took that expertise and moved into the independent

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.

DIVIDENDS

(Dollars per common share)



Dividends have increased 23 percent since 2000.

Note: Dividend amounts reflect the company's three-for-two common stock split effected in October 2003.

power business in 2001, when we built an electric generating facility in Brazil. In three short years, that segment has grown to be our third-largest earnings generator, producing earnings of $26.3 million in 2004. This segment is now responsible for 1,165 megawatts of owned and operated electric generation, including domestic power production facilities fueled by wind or natural gas. In 2005, we will seek projects with mid- to long-term contracts with quality customers while bringing a new 116-MW coal-fired facility on line in Montana.

The supplier of choice

The next phrase in our vision statement discusses being the supplier of choice in all of our markets. Many of our shareholders chose our stock because of its relative stability. Part of that stability comes from our regulated assets, which can be counted on for a steady return. Customers consistently rate our service high, while our electric generating facilities are among the most reliable in the country. We're studying the feasibility of constructing a 175-megawatt coal-fired unit that could go on line in 2010. This new generation would replace the power that we purchase from external suppliers and would support modest customer growth.

The first full year of operation for the Grasslands Pipeline contributed to record gathering and transportation volumes for our pipeline and energy services business. It enables us to access broader markets with the natural gas that we produce from our exploration and production activities. We also expanded our gathering facilities with the goal of becoming the service provider of choice in areas where production is steadily increasing.

Our utility services business is in a rebuilding phase, bringing in new leadership and adjusting its course. We expect to see significant improvement in 2005. Our restructured team will focus on being the supplier of choice while keeping a watchful eye on margins.

A safe and great place to work

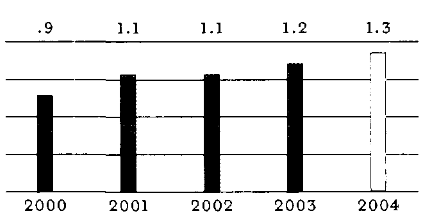
That last phrase in our vision statement, "while being a safe and great place to work," is one of the most important. Safety is a priority at MDU Resources. Our businesses are committed to doing everything possible to send every employee home safely each night. We continue our efforts to become a greater place to work. This year we surveyed employees and were pleased to learn that they continue to be proud to work here. In fact, even though the number of employees responding to the survey has grown 48 percent since 1998, our scores have remained solid. We continue to focus on a quality work environment for all of our employees.

Employees make our success possible. They drive the trucks, energize the lines and produce the fuel. They provide the products and services that help make America strong. And they do it with the best interest of our shareholders in mind. As I said earlier, it's our culture at MDU Resources, and I thank our employees for their dedication. We've had another great year. Our journey in building a legendary company continues.

Martin A. White

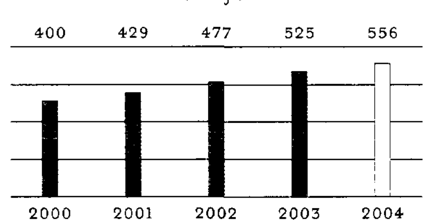
Martin A. White
Chairman of the Board, President and
Chief Executive Officer
February 22, 2005

AGGREGATE RESERVES
(In billion tons)



Recoverable aggregate reserves are a valuable asset.

NATURAL GAS AND OIL RESERVES
(In Bcfe)



Our reserve base promises a continuing domestic energy source.

Welcome to Your Boardroom

Lewis and Clark spent 146 days at Fort Mandan, North Dakota, their journey's longest stop. The Native Americans welcomed them, teaching them to survive in unfamiliar territory. Chief Sheheke said, "If we eat, you shall eat; if we starve, then you must starve also."

At MDU Resources, we've always acted as if every shareholder was present at our board table. Like Sheheke, we realize our decisions affect our shareholders; this company belongs to you, not to the board and management.

Recent scandals have caused shareholder-centered corporate governance to become the compass for corporate performance. A company focused on stakeholder accountability with sound governance practices is more likely to create value for all. It's what every public company should do. It's what MDU Resources has always done.

What is corporate governance?

Volumes have been written about corporate governance. It's a lofty-sounding phrase with many definitions. It really just means oversight of a company's management. It means the board works directly on your behalf as company owners.

Our definition has three key components: board quality and independence; processes and practices that cultivate solid decision making; and dedication to balancing stakeholder interests. Our vision statement is the foundation of our corporate governance principles. No matter how it's defined, corporate governance must be implemented by directors who have integrity and a commitment to the company's success. Your directors do.

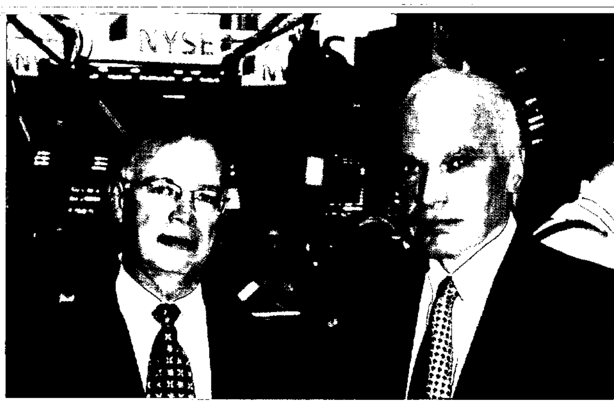
Board quality and independence

MDU Resources adopted the lead director concept before most of corporate America. It ensures that someone is authorized to call together the outside directors independent of management. Before the gurus were recommending it, MDU Resources' board was regularly holding executive sessions without management present. These are open meetings without an agenda that allow the board to discuss any concerns regarding the well-being of your company.

Martin White will retire in August 2006. We believe that choosing the next chief executive officer is one of the board's most important responsibilities. We've developed a model succession plan that is thoughtful and deliberate. It should give you confidence in the corporation's future leadership. The board has been observing internal candidates for several years and periodically assesses their progress. We will announce the CEO's successor in 2005. That person will work with Martin for more than a year, ensuring a seamless transition.

Decision-making processes

Director Homer Scott reached mandatory retirement age in February 2005. Replacing directors is a decision we take seriously. They must have the same values, competencies and commitment we require of all the directors. In many companies, the CEO primarily makes



On May 13, 2004, the MDU Resources Board of Directors visited the New York Stock Exchange in celebration of the corporation's 80th anniversary. Pictured on the Stock Exchange floor are Martin White, chairman, president and CEO and Harry Pearce, lead director.

The MDU Resources Board of Directors is an active board. The full board holds regular quarterly meetings.

the decision and the board "rubber stamps" it. Not at MDU Resources. Your board will take the time to make the right choice.

Each director is encouraged to attend educational seminars sponsored by leading organizations. In addition, Weil, Gotshal & Manges, LLP, a widely respected law firm and a nationally known leader in corporate governance, conducted training for the entire board in 2004.

Stakeholder dedication

Examples of our corporate governance leadership and stakeholder dedication include our quick decision to replace Arthur Andersen as outside auditor when corporate scandals emerged. We also decided to eliminate stock options and instead to use other stock-based compensation. But as you can see by the list on this page, corporate governance is a continuous improvement process.

In May, we reviewed an external report analyzing our compensation. It said that our directors have more compensation at risk than our peers because they receive more stock than cash. We believe that's as it should be. Director compensation is published in our proxy statement, where it states that we are paid at about the midpoint. We'll publish an executive compensation graph this year. You'll see that our executive compensation is conservative when compared to others in our industries.

Our company is incredibly transparent, which makes it easier for a stakeholder to understand us. And key to that understanding is our vision statement, which begins with two important words – "with integrity."

These meetings are usually held at company locations, and operations tours are part of the meeting. Special meetings of the board are held as needed. Committee meetings are generally held in conjunction with regular board meetings. Incumbent directors attended more than 90 percent of the combined total meetings of the board and the committees on which the director served in 2003 and 2004.

Corporate Governance

We continue to meet and/or exceed corporate governance standards. Examples of this year's activities:

- Identified four board members as audit committee financial experts.
- Disclosed independent auditor fees in 2004 proxy statement.
- Applied independence standards to the audit committee and determined each member satisfies the requirements.
- Prepared systems and procedures to comply with Section 404 of the Sarbanes-Oxley Act of 2002, which mandates an annual evaluation of internal controls.
- Adopted an attorney reporting policy, in compliance with SOX Section 307, which establishes rules for attorneys who appear before the Securities and Exchange Commission.
- Established a procedure for confidential communications with the Audit Committee. A hotline system for receiving complaints confidentially was developed.
- Adopted a policy regarding hiring current or former employees of the external independent auditor.
- Implemented additional disclosure controls and procedures in order to comply with the new requirements of SOX Section 404 and accelerated Form 10-K reporting requirements.
- Continued to include and update the code of conduct for directors, officers and employees, and the company's general ethics guidelines on the company Web site at www.mdu.com.

Board Changes
Homer A. Scott Jr. retired February 10, 2005, from the MDU Resources Board of Directors.

Audit Committee
Dennis W. Johnson, Chairman
Bruce R. Albertson
John L. Olson
Harry J. Pearce
John K. Wilson

Compensation Committee
Harry J. Pearce, Chairman
Thomas Everist
Patricia L. Moss

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.

Martin A. White, 63 (7)
Mandan, North Dakota

Chairman of MDU Resources Board of Directors

President and Chief Executive Officer of MDU Resources

Harry J. Pearce, 62 (8)
Detroit, Michigan

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 GM; also serves as a director of several major corporations

Expertise: Multinational business management, finance, engineering and law

Bruce R. Albertson, 59 (4)
Pompano Beach, Florida

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

Expertise: Technology, finance, marketing and international business

Thomas Everist, 55 (9)
Sioux Falls, South Dakota

President and chairman of The Everist Co., an aggregate, concrete and asphalt production company; also serves as a director of several other corporations

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

Dennis W. Johnson, 55 (4)
Dickinson, North Dakota

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

Expertise: Business management, engineering and finance

Patricia L. Moss, 51 (1)
Bend, Oregon

President, chief executive officer and a director of Cascade Bancorp and Bank of the Cascades; also serves as a director of several other corporations

Expertise: Finance and human resources

Robert L. Nance, 68 (12)
Billings, Montana

President, chief executive officer and director of Nance Petroleum Corp., an oil and natural gas exploration company and senior vice president of St. Mary Land & Exploration Co.; also serves as a director of a bank and as a member of the executive committee of a petroleum industry organization

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

John L. Olson, 65 (20)
Sidney, Montana

President and chief executive officer of Blue Rock Products Co. and Blue Rock Distributing Co., beverage bottling and distributing companies, and chairman of the board of Admiral Beverage Corp. with operations and franchises in the Rocky Mountain states; also serves as a director of a health insurance company

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

Homer A. Scott Jr., 69 (24)
Sheridan, Wyoming

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

Expertise: Construction industry, finance and banking

Sister Thomas Welder, O.S.B., 64 (17)
Bismarck, North Dakota

President of University of Mary, a director of several organizations and a past member of the Consultant-Evaluator Corps for the North Central Association of Colleges and Schools

Expertise: Business development and management

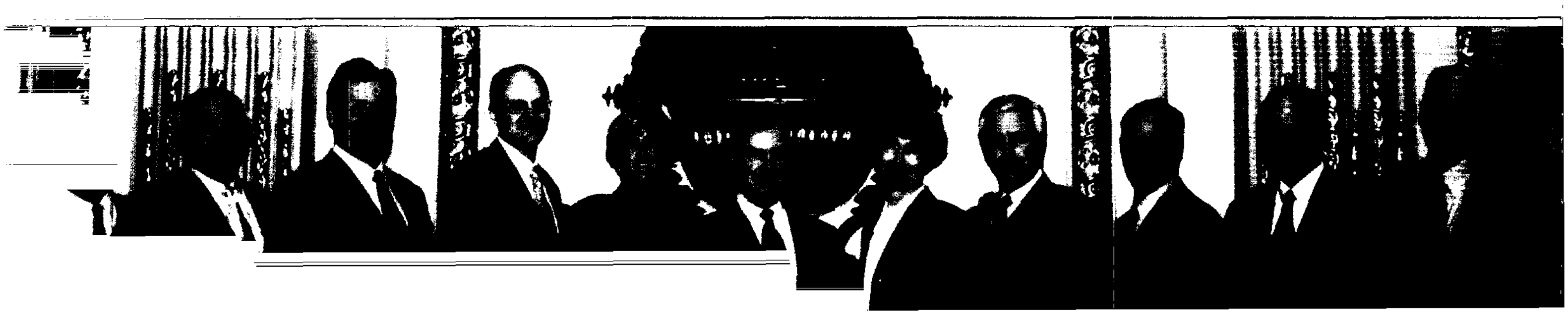
John K. Wilson, 50 (1)
Omaha, Nebraska

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

Expertise: Finance and natural gas industry

Expanded biographies of all board members can be found in the 2005 MDU Resources Proxy Statement.

Numbers indicate age and years of service ( ) on the MDU Resources Board of Directors as of December 31, 2004.



Management Policy Committee

Martin A. White, 63 (13)
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; formerly 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, 50 (22)
President and Chief Executive Officer, WBI Holdings, Inc.

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

Paul Gatzemeier, 54 (3)
President and Chief Executive Officer, Centennial Energy Resources LLC

Serves as chief executive officer of all domestic and international independent power production subsidiaries of Centennial Energy Resources; formerly held executive positions with another energy company and was a private business consultant specializing in energy companies

Terry D. Hildestad, 55 (30)
President and Chief Executive Officer, Knife River Corporation

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

Bruce T. Imsdahl, 56 (34)
President and Chief Executive Officer, Montana-Dakota Utilities Co. and Great Plains Natural Gas Co.

Formerly held executive and management positions with Montana-Dakota

Cindy C. Redding, 46 (2)
Vice President-Human Resources, MDU Resources

Formerly held domestic and international human resources management positions in the energy, health care and global packaging industries with several major corporations

Warren L. Robinson, 54 (16)
Executive Vice President and Chief Financial Officer, MDU Resources

Serves as the senior financial officer and member of the boards of directors of all major subsidiary companies; formerly held executive and management positions in finance, corporate planning and development with the company, as well as with several natural gas utility companies

Paul K. Sandness, 50 (24)
General Counsel and Secretary, MDU Resources

Serves as general counsel and secretary for all major company subsidiaries; formerly senior attorney and held other positions of increasing responsibility with MDU Resources

Other Corporate and Senior Company Officers

Cathleen M. Christopherson, 60 (37)
Vice President-Corporate Communications, MDU Resources

Mary B. Hager, 41 (11)
Controller, MDU Resources

John G. Harp, 52 (28)
President and Chief Executive Officer, Utility Services, Inc.

Vernon A. Raile, 59 (24)
Senior Vice President and Chief Accounting Officer, MDU Resources

Daryl A. Splichal, 49 (24)
Treasurer, MDU Resources

Floyd E. Wilson, 54 (23)
Vice President-Strategic Planning and Corporate Development, MDU Resources

Robert E. Wood, 62 (30)
Senior Vice President-Governmental and Public Affairs, MDU Resources

Management Changes

Paul K. Sandness was named general counsel and secretary effective April 6, 2004.

Robert E. Wood was named senior vice president-governmental and public affairs on May 13, 2004.

Ronald D. Tipton, chief executive officer of Montana-Dakota Utilities Co., Great Plains Natural Gas Co. and Utility Services, Inc., announced his retirement September 24, 2004.

John G. Harp was named president and chief executive officer of Utility Services, Inc. on September 29, 2004.

Bruce Imsdahl has been president of Montana-Dakota and Great Plains since July 2003, and was named chief executive officer on November 11, 2004.

Paul Gatzemeier was named president and chief executive officer of Centennial Energy Resources LLC on November 11, 2004.

Numbers indicate age and years of service ( ) as of December 31, 2004.

Pictured here is the MDU Resources Board of Directors at a visit to the New York Stock Exchange, marking the corporation's 80th anniversary.

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

A Legendary Journey

JANUARY 18, 1803
U.S. President Thomas Jefferson sends a secret message to Congress asking for approval of an expedition to explore the western part of the continent.

SPRING 1803
Meriwether Lewis, Jefferson's secretary, begins his training as the expedition's leader. He studies with America's leading scientists at the American Philosophical Society in Philadelphia. He also begins complex logistical preparations, gathering scientific instruments and medical supplies.

JULY 4, 1803
Jefferson announces the $15 million Louisiana Purchase from France, more than doubling the size of the United States.

SUMMER/FALL 1803
Lewis oversees construction of a keelboat, then picks up William Clark and other recruits of "hardy stock" as he travels from Philadelphia toward St. Louis. They set up winter camp on the Wood River in Illinois.

MAY 14, 1804
The Corps of Discovery leaves Camp River Dubois with 33 permanent party members and begins its journey up the Missouri River "under a gentle breeze."

AUGUST 3, 1804
Lewis and Clark hold their first council with Native American tribes, near present-day Omaha, Nebraska.

AUGUST 20, 1804
Sgt. Charles Floyd dies of natural causes (probably a ruptured appendix) near present-day Sioux City, Iowa. He is the only member fatality during the expedition.

OCTOBER 24, 1804
Near today's Bismarck, North Dakota, the Corps arrives at the villages of the Mandan and Hidatsa, buffalo-hunting tribes that live along the Missouri River.

NOVEMBER 4, 1804
Lewis and Clark hire French-Canadian fur trader Toussaint Charbonneau and his 15-year-old Shoshone wife, Sakakawea, as interpreters on the journey ahead.

DECEMBER 24, 1804
The men finish building Fort Mandan, their winter quarters near present-day Washburn, North Dakota.

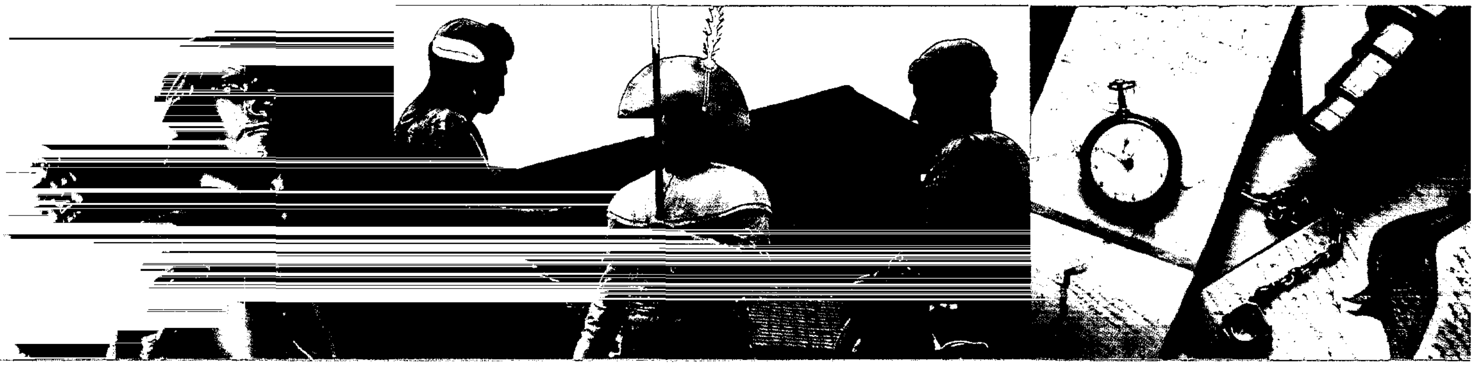
FEBRUARY 11, 1805
Sakakawea's son, Jean Baptiste Charbonneau – nicknamed Pomp by Clark – is born with assistance from Lewis.

APRIL 7, 1805
Lewis and Clark send a shipment of artifacts and specimens to President Jefferson; the party heads west.

MAY 16, 1805
One of their boats nearly overturns; Lewis credits Sakakawea with saving their most important possessions.

JUNE 1, 1805
The Corps reaches an unknown fork, today known as the Confluence of the Missouri and Yellowstone rivers near the North Dakota-Montana border, and must determine which branch to choose. They take the northern route, although the party splits several times to explore the area.

JUNE 13, 1805
Lewis reaches the Great Falls of the Missouri – five massive cascades around which the party must carry all of its gear, including the canoes.



AUGUST 12, 1805
Lewis finds the headwaters of the Missouri River, crosses the Continental Divide and Lemhi Pass (near the present-day Montana-Idaho border) and is bitterly disappointed as he realizes there is no Northwest Passage.

AUGUST 17, 1805
The main party arrives at the Shoshone camp; Sakakawea recognizes the chief as her long-lost brother.

AUGUST 31, 1805
The expedition sets out for the Bitterroot Mountains with horses and a mule acquired from the Shoshone. The crossing will cover more than 160 miles.

SEPTEMBER 23, 1805
Starving, the Corps emerges from the mountains near present-day Weippe, Idaho, at the villages of the Nez Perce Indians.

OCTOBER 7, 1805
After learning a new method to make dugout canoes from the Nez Perce, the men push off down the Clearwater River near Orofino, Idaho; it's the first time they've traveled with the current at their back in almost two years.

OCTOBER 16, 1805
The expedition reaches the Columbia River, the last waterway to the Pacific. They must traverse treacherous rapids on the way.

NOVEMBER 18, 1805
Lewis and Clark reach the Pacific Ocean. The entire expedition, including Sakakawea and Clark's slave, York, vote on where to build their winter quarters. They choose the Clatsop Indian side of the Columbia.

MARCH 23, 1806
After a winter of only 12 days without rain, the Corps of Discovery begins its return trip.

JUNE 29, 1806
The party divides near present-day Lolo, Montana, to explore shorter routes home and to determine the northern boundary of the Louisiana Purchase. Lewis goes north and Clark heads south.

JULY 25, 1806
Clark arrives at a "remarkable rock" near present-day Billings, Montana, which he names Pompey's Tower (Pillar) after Sakakawea's son. He carves his name and the date into the rock. It is the only physical evidence of the expedition along the trail.

AUGUST 12, 1806
The parties reunite at the Confluence of the Yellowstone and Missouri rivers. The Charbonneau family leaves the party and returns home. Swift currents enable the Corps to cover as much as 70 miles per day on their way back down the Missouri.

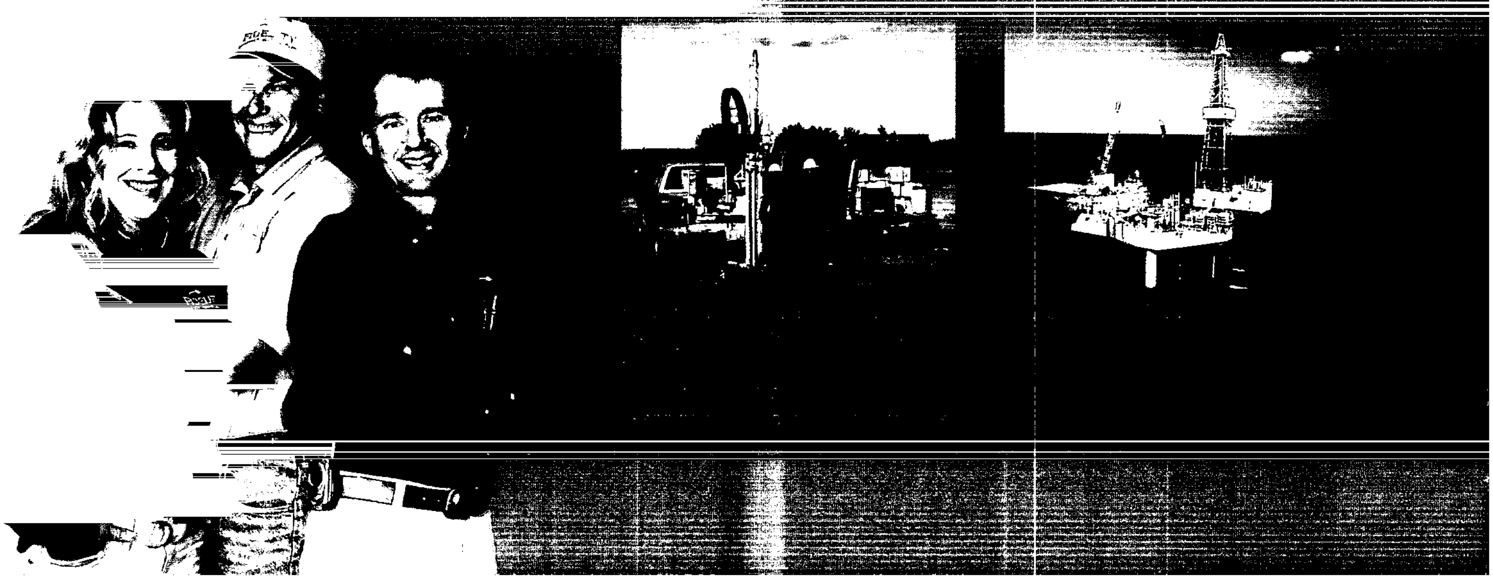
SEPTEMBER 23, 1806
The party arrives in St. Louis, and the men are acclaimed national heroes.

Left: A statue of Sakakawea and her son Jean Baptiste at the Capitol Grounds in Bismarck, North Dakota. A replica of the statue now resides in the National Statuary Hall in Washington, D.C.

Middle: These 12-ft. steel figures of Mandan Chief Sheheke, Lewis and Clark can be seen at the entrance to the North Dakota Lewis & Clark Interpretive Center in Harmony Park, near Washburn, North Dakota. They memorialize the hospitality that enabled Lewis and Clark to continue their journey. MDU Resources Foundation made significant contributions to development of the interpretive center. (Photo provided by the Lewis & Clark Fort Mandan Foundation).

Right: The Lewis & Clark National Bicentennial Exhibition brings together hundreds of artifacts and documents from the expedition. Some of them are pictured in the following sections.


FIDELITY
Earnings reach all-time high



Exploring our Resources

Lewis and Clark noticed coal veins in the hills, but couldn't have imagined the Louisiana Purchase's abundant natural resources and their future contribution to a strong America. Fidelity Exploration & Production grew from the need to fuel the corporation's power plants in the 1920s. Today its natural gas and oil production business is setting earnings records.

Earnings in 2004 reached an all-time high at Fidelity. Natural gas and oil prices were significantly higher in 2004 than in 2003, but that's only part of the story. Fidelity's journey to today's success is marked by specific strategies to build long-term shareholder value by focusing on maintaining a diverse, high-quality asset portfolio. It has significant production from traditional natural gas and oil properties in the Rocky Mountain region and in the Gulf of Mexico, and it is a large producer of coalbed natural gas.

Record production, growing reserves

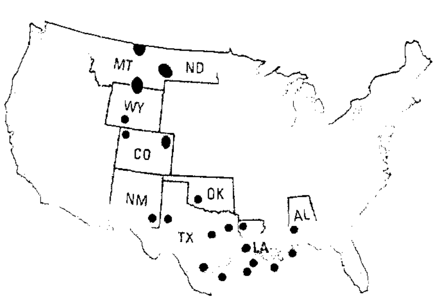
Fidelity has concentrated on increasing production each year, while continuing to grow reserves to replace produced volumes. In addition to acquiring reserves, the company has been successful in using new technology to enhance production from long-lived fields. For example, the company has owned assets in Montana for more than 60 years that continue to set production records.

Fidelity also is continually reviewing and testing new projects and new areas to enhance future growth. Drilling opportunities have increased with acreage expansion.

The largest challenge to increasing production while growing reserves centers around delays in obtaining regulatory approvals, which is affecting producers throughout the Rocky Mountain region. However, despite these difficulties, Fidelity has been able to grow production at a compound annual rate of 15 percent over the last five years, while growing its proven reserves at a compound annual rate of 9 percent over the same period.

Environmental, outreach awards

Fidelity earned a major environmental stewardship award from the Interstate Oil and Gas Compact Commission in October 2004 for its sponsorship of a three-year soil and crop testing program. The program monitors water and soil conditions for potential impacts from coalbed natural gas production. The company also was honored with a public outreach and education award from the national office of the Bureau of Land Management in June 2004. A BLM news release announcing Fidelity's selection for this award said the company "has been an exemplary operator in Montana and Wyoming's Powder River Basin for many years." The announcement also said the company "makes working with landowners a priority."



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

• Area of principal production and reserves

Expanding our Reserves

Knife River Corporation is named for the river that flows near the Indian villages of the same name where Lewis and Clark met Sakakawea. Expanding on its expertise in mining coal reserves near the explorers' trail, Knife River moved into the construction materials and mining business in 1992. It is now one of the top 10 aggregate producers in America.

The Hidatsa and Mandan nations lived in earth lodges in the Knife River Indian Villages, for centuries a trading hub for flint. Like the Native Americans of Sakakawea's time, Knife River helps build a strong nation in creating goods and services from natural resources. Operations today are aggregate based.

The U.S. Geological Survey predicts the United States will use as much aggregate in the next 25 years as it has used in the previous 100 years combined, which is good news for the industry's future.

Growth balances challenging weather

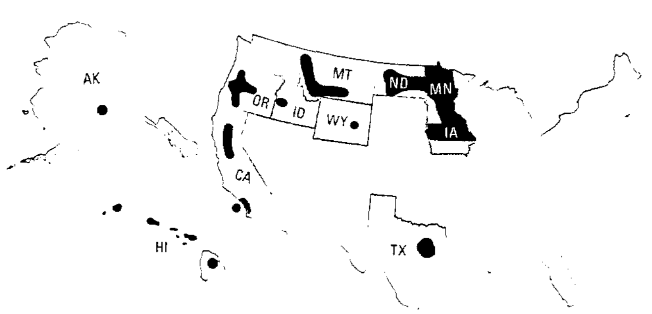
A booming housing market and increasing funding for highways contributed to Knife River's earnings. Housing starts increased 6.4 percent in October, according to the Commerce Department, the highest level since December 2003. Despite uncertainty over future federal highway funding that slowed construction projects in some states, the company experienced a good year.

For the past several years, sales were down in the Portland, Oregon, area, a hub for Knife River companies. This year, the Oregon economy began to rebound while some other operations experienced more competitive markets. Also while Knife River operations in Texas experienced significant rain delays, Knife River's geographic diversity paid off again when sister companies worked long, sunny days in other regions. As a result, every major product line had record sales.

The company expanded into two new geographic regions in 2004 – Iowa and Idaho. This increased its reserve base, which now totals 1.3 billion tons. Most of the company's strategically located reserves are permitted, an increasingly valuable asset in an age marked by strenuous permitting requirements. At current production rates, these reserves are expected to last the company about 30 years. This long-term, reserve-based strategy, consistent throughout the MDU Resources family of companies, should serve shareholders well for years to come.

Employees working safer, smarter

A program called START – Supervisor Training in Accident Reduction Techniques – has helped cut recordable incidence rates. Employees throughout the corporation are communicating face-to-face through an annual conference this year called "Share the Knowledge," as well as online, sharing best practices in operations and technology.

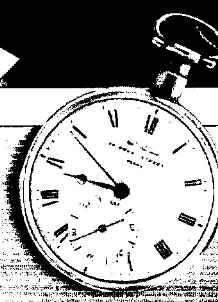


Knife River Corporation mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt and other value-added products, as well as performs integrated construction services, in the central and western United States, and in the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

• Construction materials locations

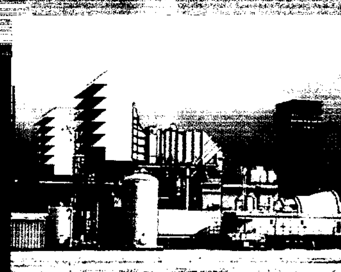
Geographic diversity pays off

[illegible], transportation manager, helped design the new barge load-out facility at MBI in Oregon. [illegible] the company a dominant player along the Columbia River and beyond.

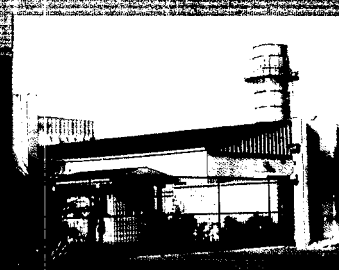


The water in the course of time has trickled
down the soft sand clifts and woarn it into
a thousand figures, which are made to represent
elegant ranges of lofty freestone buildings ...
the range of columns did not the less remind
us of some of those large stone buildings
in the United States. — LEWIS, MAY 31, 1805

Raymond Vasquez of Young Contractors and Richard Van Heel and Pat Sand of Bauerly Brothers.



CFR has a 50 percent ownership interest in this electric generating facility in Hartwell, Georgia.



This electric generating facility is the newest and lowest-cost electricity provider in Trinidad and Tobago.

Taming Uncharted Territories

Electricity was in its infancy in 1806 when Lewis mentioned it in his journal. It wasn't until 1882 that Thomas Edison lit New York with electricity, but soon it was powering America's growth. Centennial Energy Resources is growing rapidly as an independent power producer and is building a plant near Lewis and Clark's trail.

Late in 2005, electricity is expected to be produced near Hardin, Montana, 37 miles from where Clark carved his name in a rock he named after Sakakawea's son. In April 2004, Rocky Mountain Power, a CER subsidiary, entered into a power sales agreement for the entire output of the 116-megawatt coal-fired plant.

That sales agreement is one of the milestones achieved by CER in 2004 in solidifying its disciplined strategies as an independent power producer. Those strategies revolve around seeking opportunities for long-term relationships with financially stable customers.

Growing internationally

MDU Brasil, through its interest in its electric generating facility in northeastern Brazil, contributed significantly to CER's record earnings in 2004.

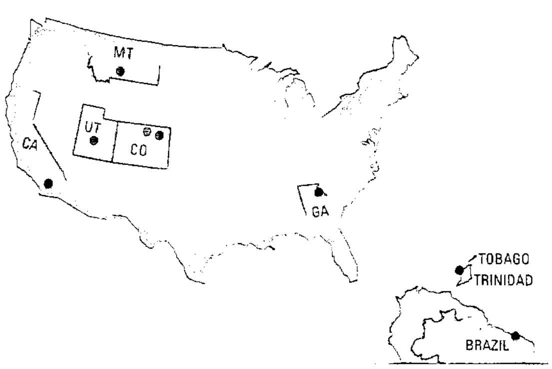
Brazil's currency has stabilized and its economic indicators look strong. To securely position itself for expansion, MDU Brasil broadened its management depth by naming a president who is well respected and influential in Brazil's business and regulatory sectors.

In February 2004, a 49.99 percent ownership interest was acquired in a 225-megawatt natural gas-fired electric generating facility in Trinidad and Tobago. It is the newest and lowest-cost electricity provider in the area and has 25 years remaining on its power purchase agreement.

Growing domestically

On the domestic side, Colorado Energy Management was acquired in April, accomplishing the company's goal of acquiring an operating and development company. CEM provides operations and maintenance services for customers owning generating facilities. It has provided reliable energy solutions to the independent power production industry for years, and its management expertise complements CER's existing technical and operating experience.

In September, CER finalized an agreement for 50-percent ownership in a 310-MW natural gas-fired electric generating facility in Hartwell, Georgia. It has 15 years remaining under its power purchase agreement.



Centennial Energy Resources LLC owns, builds and operates electric generating facilities in the United States and has investments in domestic and international natural resource-based projects. Electric capacity and energy produced at its power plants primarily are sold under mid- and long-term contracts to nonaffiliated entities.

- Independent power production locations
- Independent power production locations operated for others
- Independent power production locations owned and operated

Blazing the Trail

In 1924, Montana-Dakota brought all-day electricity to customers in the heart of Lewis and Clark country. Like the famed explorers' dedication to their mission, the company was dedicated to establishing essential service in America's Heartland. Today it serves more than 300,000 customers in five states with safe, reliable electricity and natural gas.

Lewis and Clark undoubtedly spent some cold, dark nights longing for the comforts of home. Two hundred years later, customers simply flip a switch when days get shorter and temperatures drop.

The company works diligently to provide efficient, dependable service. It is increasing its use of subbituminous coal, blending it with lignite at the R.M. Heskett and Lewis & Clark stations, to reduce emissions and increase boiler efficiencies. Heskett Station, Unit 1, celebrated its 50th anniversary. Despite its age, the unit had a 93.2 percent average availability for the past 10 years, compared to the national average of 89.5 percent. The company owns a 25 percent share of Coyote Station, which ranks 20th lowest out of 299 power plants in the nation in cost of production per megawatt-hour. That's helped keep electric rates stable.

Sales and service growth

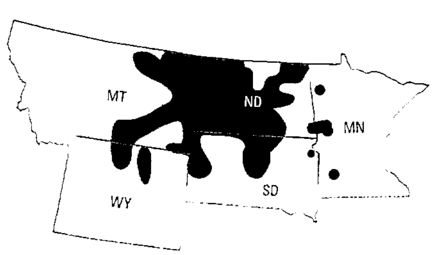
Industrial loads are increasing, particularly in larger cities and the oil fields. More than 3,000 residential natural gas customers were added. Several state commissions approved rate relief, helping to offset higher expenses for providing natural gas service.

The company's positioning statement is "In the Community to Serve," and employees take pride in it. Its call center handles calls in an average of 19 seconds, compared to the Incoming Call Management Institute's utility average of 47 seconds. The latest in-truck technology helps representatives work with service personnel to balance workload, reduce paperwork and dispatch efficiently.

Large military projects will enhance shareholder return. One of the projects is a $3.5 million contract with Ellsworth Air Force Base in South Dakota, a joint project with the company's pipeline and energy services segment, to provide energy efficiency project management. The company also has a contract with the potential to bring in $1.7 million to update more than 200 missile sites in North Dakota.

New power plant on horizon

The company filed a North Dakota air-quality permit application as it studies the feasibility of building a coal-fired plant to meet future electricity needs. It also is researching alternative locations. Transmission access, fuel supply and environmental considerations will be major factors in the decision.



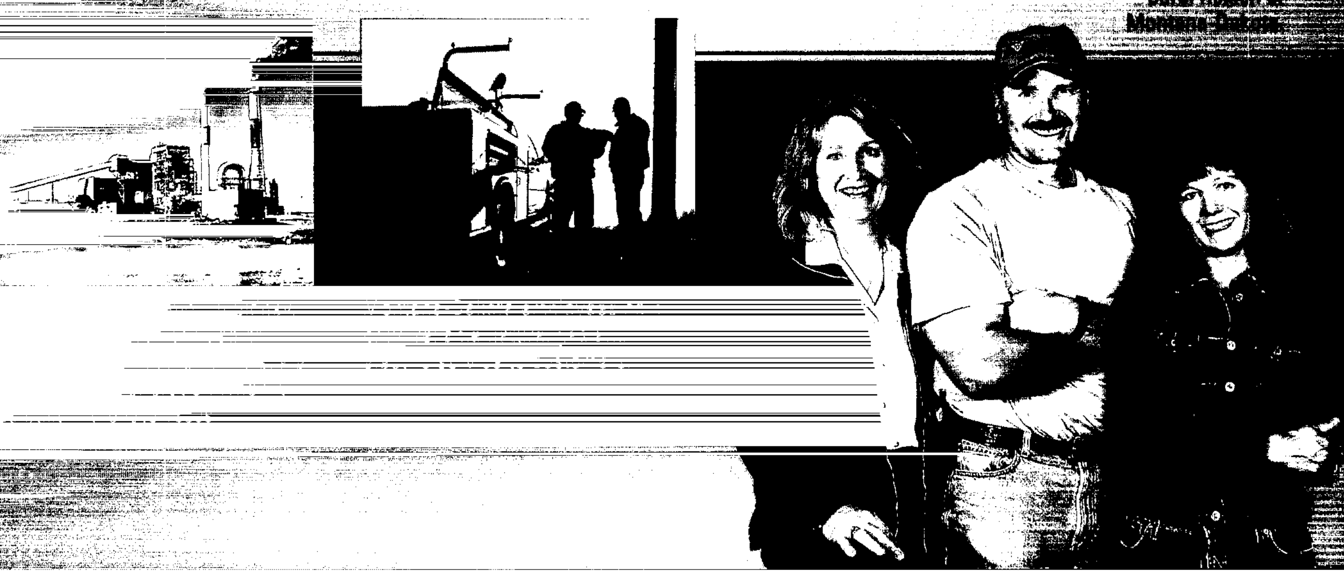
Montana-Dakota Utilities Co. generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Great Plains Natural Gas Co. serves natural gas customers in western Minnesota and southeastern North Dakota. These operations also supply related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

- Electric and natural gas distribution area
- Electric generating stations

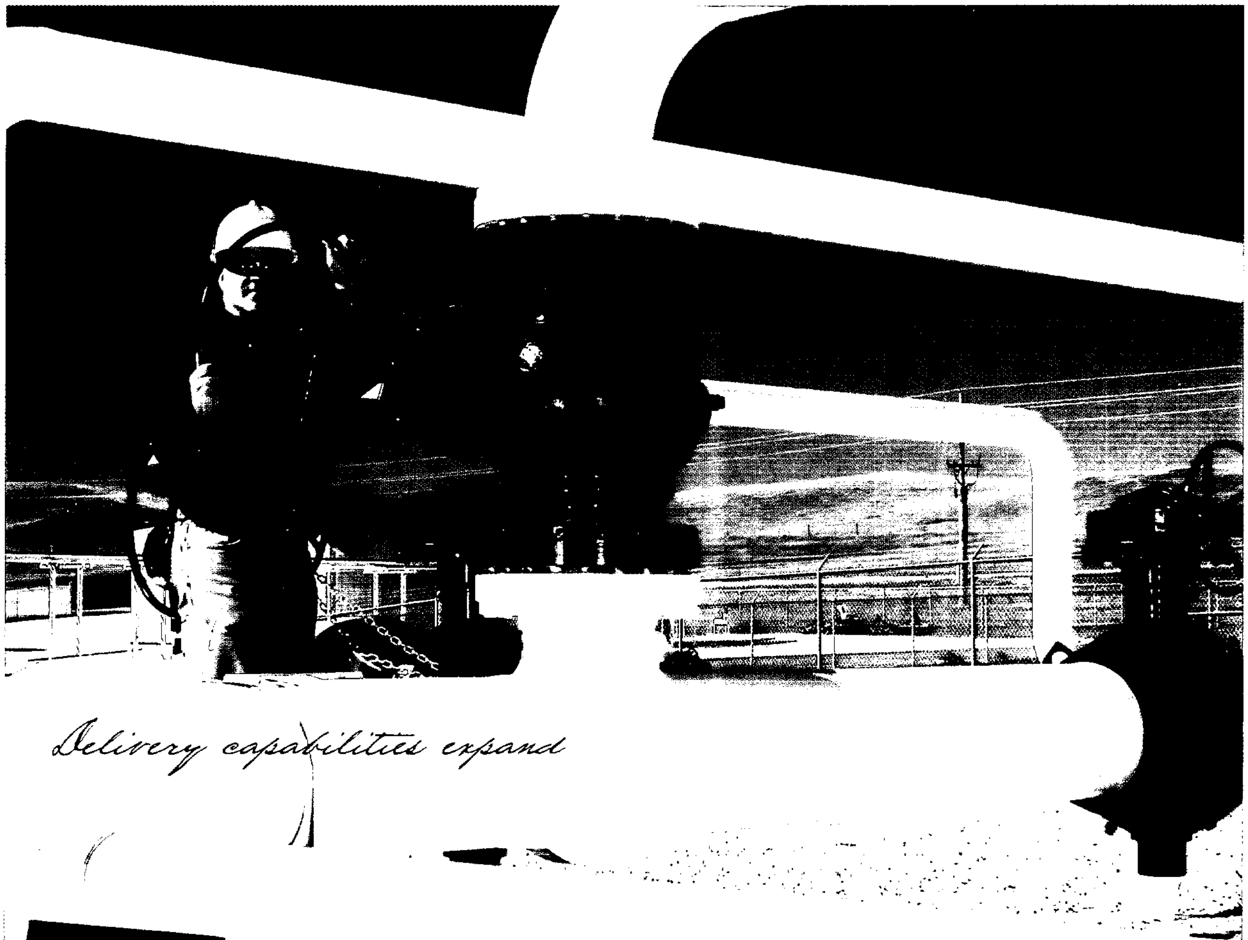
a natural gas construction project in Bismarck, North Dakota, a community on Lewis and Clark Trail.

we exhausted the last of our candles, ...ely had taken the precaution to bring ...ds and wick, by means of which and tallow in our possession we do not yet ...elves destitute of this necessary article.

...13, 1806



Myrlene Wollender, Duane Homer and Carol Kolech of Montana-Dakota

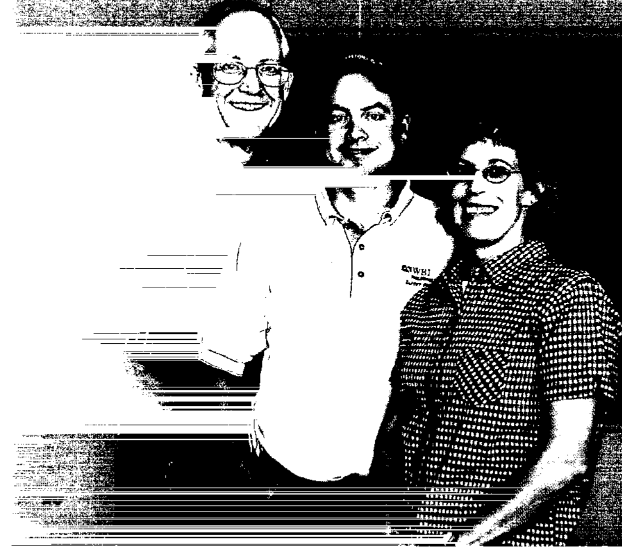


Delivery capabilities expand

[illegible] works at WBI's newest compressor station in western North Dakota, which was built in conjunction with the Grasslands Pipeline.

We persuaded them to remain at peace and that they might depend on getting supplies through the channel of the Missouri, but it required time to put the trade in operation. — CLARK, NOVEMBER [illegible]

[illegible]



Charting our Course

Lewis and Clark's mission was to find a route over which to move goods from civilized America through unknown territories to the Pacific Ocean. The mission of WBI Holding's pipeline business is to provide a means to gather, store and transport natural gas to population centers. WBI is the modern-day realization of Thomas Jefferson's vision of commerce.

Running inconspicuously underground through areas near those traveled by the Corps of Discovery, the Grasslands Pipeline in December 2004 completed its first full year of operation. As a result of Grasslands and other enhancements, WBI experienced record gathering and transportation volumes in 2004.

Grasslands is the largest pipeline project ever undertaken by the company. The 253-mile pipeline transports natural gas from the Rocky Mountain region to interconnecting pipelines, helping to deliver the valuable commodity to large Midwestern markets. Firm natural gas capacity on the Grasslands Pipeline is 90 million cubic feet per day with expansion possible to 200 million cubic feet per day.

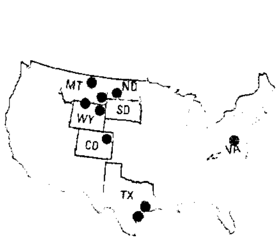
Expansions enhance access

In addition to planning for a possible Grasslands expansion, gathering facility expansion was ongoing in Montana and Wyoming in 2004. New gathering lines and interconnects were constructed to access the increasing natural gas production in the Rocky Mountain region. In addition, 2004 saw large volumes of natural gas moved into storage by interruptible customers in anticipation of higher winter prices. In fact, September was the largest single month of storage injections that WBI has experienced since inception of open access on the pipeline transmission system.

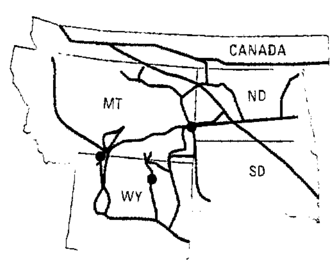
Growth in the use of the company's gathering systems also is occurring as drilling opportunities increase in the areas in which it operates. The company seeks to maximize the use of its existing gathering, transmission and storage facilities by adding more services for new customers, as well as growing with the corporation's natural gas and oil production segment.

Product development challenging

The company's cable and pipeline magnetization and locating business has been developing new technology for detecting buried plastic objects, including pipeline and unexploded ordnance such as land mines. While it is taking longer to bring the technology to market than expected, the company believes the technology is superior and has great potential once it gains market acceptance.



- ◉ Energy services offices
- • Pipeline gathering systems



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.

- • Company storage fields
- – Transmission pipeline system
- – Interconnecting pipelines

The company's energy-services business also has an office in Bury St. Edmunds, England.

Mapping new Strategies

Lewis and Clark left St. Louis in 1804, embarking on a journey of enormous challenges that required the experience and creativity of the explorers and their crew. MDU Resources' utility services companies have seen rough waters and are drawing on their management experience and employee creativity as they map new strategies.

MDU Resources' utility services companies have had their share of challenges the past few years. Integration issues common to companies that grow by acquisition affected this segment as it went through a rapid expansion from 1997 through 2002.

An uncertain economy then affected many of its businesses as new contracts became scarce and margins tightened. While MDU Resources' companies fared better than many in the utility services business where bankruptcies have become common, it was time to take a fresh look at the business.

Sharpening our focus

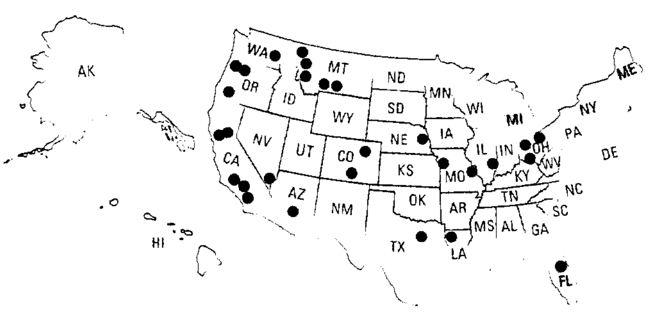
In late 2004, the utility services segment reorganized and set a new course. Its sharpened focus will be on profitable markets and profitable customers. Leadership of this segment changed, as did the reporting relationships of the business units. Enhanced succession planning and teambuilding across company lines are major focuses. New real-time communication technology will help tie companies together, no matter where they're located.

The company experienced a loss in 2004, but next year's financial results are expected to improve considerably. Work backlog as of December 31, 2004, was about $238 million, compared to $148 million at December 31, 2003.

Future looks brighter

As the economy rebounds, so should the work for utility services companies. Outside electrical line work is picking up, especially on the West Coast. Demand for inside electrical work, particularly in the health care industry, also is increasing.

The company's philosophy of acquiring only strong utility services companies served it well during a soft economy and will continue. However, opportunities to acquire compatible companies will be carefully considered.



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

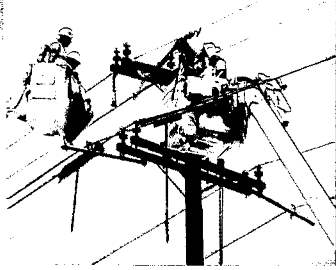
- Utility services offices

State names indicate authorized states of operations

Reorganization sharpens focus

... general foreman for Bell Electrical, helped with several large projects ... in downtown St. Louis.

I reflected on the difficulties which ... barrier would most probably throw ... it in some measure counterbalanced ... I had felt; but as I have always held ... to anticipate evils, I will believe it ... comfortable road until I am compelled ... differently. — LEWIS, MAY 26, 1805



Frank Richardson and
Laurie Hayden of
Utility Services, Inc.

Our Company

OUR VISION

OUR MISSION

OUR GUIDING PRINCIPLES

CUSTOMERS

STOCKHOLDERS

COMMUNITY

ENVIRONMENT

ETHICS

EMPLOYEES

SAFETY

OUR BUSINESSES

Construction Materials and Mining
Alaska Basic Industries, Inc.
Anchorage Sand and Gravel, Inc.
Atlas, Inc.
Baldwin Contracting Company, Inc.
Bauerly Brothers, Inc.
Beaver State Ready-Mix, Inc.
Becker Gravel Company, Inc.
Bracelin-Yeager Concrete
Buffalo Bituminous, Inc.
Central Oregon Redi-Mix, L.L.C.
Concrete, Inc.
Connolly-Pacific Co.
DSS Company
Empire Sand & Gravel Company
Fred Carlson Company, LLC
Granite City Ready Mix, Inc.
Hap Taylor & Sons, Inc.
Hawaiian Cement
JTL Group, Inc.
Kalispell Ready Mix
Knife River Corporation
KRC Aggregate, Inc.
KRC Holdings, Inc.
LTM, Incorporated
Masco, Inc.
MBI (Morse Bros., Inc.)
McElroy and Wilken, Inc.
Medford Ready Mix, Inc.
Missoula Ready Mix
Northstar Materials, Inc.
Pederson Bros. of Harmony
Pioneer Construction, Inc.
Polson Ready Mix Concrete, Inc.
Rogue Aggregates, Inc.
Roseburg Paving Co.
Roverud Construction
West Hawaii Concrete
Young Contractors, Inc.

Electric and Natural Gas Distribution
Great Plains Natural Gas Co.
Montana-Dakota Utilities Co.

Independent Power Production
Centennial Energy Resources LLC
Centennial Power, Inc.
Colorado Energy Management, LLC
MDU Brasil Ltda.

Natural Gas and Oil Production
Fidelity Exploration & Production Company

Pipeline and Energy Services
Bitter Creek Pipelines, LLC
Innovatum International Limited
Innovatum, Inc.
Prairielands Energy Marketing, Inc.
Subsurface Instruments
WBI Holdings, Inc.
Williston Basin Interstate Pipeline Company

Utility Services
Bell Electrical Contractors, Inc.
Capital Electric Construction Company, Inc.
Capital Electric Line Builders, Inc.
E.S.I. Inc.
Frebco, Inc.
Hamlin Electric Company
High Line Equipment
International Line Builders, Inc.
Loy Clark Pipeline Co.
Oregon Electric Group
Pouk & Steinle, Inc.
Rocky Mountain Contractors, Inc.
The Wagner-Smith Company
Utility Services, Inc.
Wagner-Smith Equipment Co.

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2004

OR

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

For the transition period from ______________ to ______________

Commission file number 1-3480

MDU RESOURCES GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware	41-0423660
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

Schuchart Building
918 East Divide Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 222-7900
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00 and Preference Share Purchase Rights	New York Stock Exchange Pacific Stock Exchange

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

Preferred Stock, par value $100
(Title of Class)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X . No _.

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Yes X . No _.

State the aggregate market value of the voting stock held by nonaffiliates of the registrant as of June 30, 2004: $2,822,813,000.

Indicate the number of shares outstanding of each of the Registrant's classes of common stock, as of February 17, 2005: 118,292,354 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the Registrant's 2005 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12 and 14 of this Report.

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. 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. In addition to the risk factors and cautionary statements included in this Form 10-K at Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations (MD&A) – Risk Factors and Cautionary Statements that May Affect Future Results, the following are some other factors that should be considered for a better understanding of the financial condition of MDU Resources Group, Inc. (Company). These other factors may impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities
- Changes in operation, performance and construction of plant facilities or other assets
- Changes in present or prospective generation
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, and/or available supplies of, energy products and services
- Cyclical nature of large construction projects at certain operations
- Changes in tax rates or policies
- Unanticipated project delays or changes in project costs
- Unanticipated changes in operating expenses or capital expenditures
- Labor negotiations or disputes
- *Inability of the various contract counterparties to meet their contractual obligations*
- Changes in accounting principles and/or the application of such principles to the Company
- Changes in technology
- Changes in legal or regulatory proceedings
- The ability to effectively integrate the operations of acquired companies
- Fluctuations in natural gas and crude oil prices
- Decline in general economic environment
- Changes in governmental regulation
- Changes in currency exchange rates
- Unanticipated increases in competition
- Variations in weather

ITEMS 1 AND 2. BUSINESS AND PROPERTIES

GENERAL

The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at the Schuchart Building, 918 East Divide Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 222-7900.

Montana-Dakota Utilities Co. (Montana-Dakota), a public utility division of the Company, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in the northern Great Plains. Great Plains Natural Gas Co. (Great Plains), another public utility division of the Company, distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added products and services in the northern Great Plains.

The Company, through its wholly owned subsidiary, Centennial Energy Holdings, Inc. (Centennial), owns WBI Holdings, Inc. (WBI Holdings), Knife River Corporation (Knife River), Utility Services, Inc. (Utility Services), Centennial Energy Resources LLC (Centennial Resources) and Centennial Holdings Capital LLC (Centennial Capital).

WBI Holdings is comprised of the pipeline and energy services and the natural gas and oil production segments. 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, development and production activities, primarily in the Rocky Mountain region of the United States and in and around the Gulf of Mexico.

Knife River 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.

Utility Services specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling, and the manufacture and distribution of specialty equipment.

Centennial Resources owns, builds and operates electric generating facilities in the United States and has investments in domestic and international natural resource-based projects. Electric capacity and energy produced at its power plants are sold primarily under mid- and long-term contracts to nonaffiliated entities.

Centennial Capital insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property and contract rights. These activities are reflected in the Other category.

As of December 31, 2004, the Company had 8,058 full-time employees with 100 employed at MDU Resources Group, Inc., 903 at Montana-Dakota, 55 at Great Plains, 478 at WBI Holdings, 4,015 at Knife River, 2,414 at Utility Services and 93 at Centennial Resources. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

At Montana-Dakota and Williston Basin Interstate Pipeline Company (Williston Basin), an indirect wholly owned subsidiary of WBI Holdings, 433 and 75 employees, respectively, are represented by the International Brotherhood of Electrical Workers (IBEW). Labor contracts with such employees are in effect through April 30, 2007 and March 31, 2005, for Montana-Dakota and Williston Basin, respectively. Williston Basin is currently in negotiations with the IBEW relative to its contract.

Knife River has 41 labor contracts that represent 662 of its construction materials employees. Knife River is currently in negotiations on one of its labor contracts.

Utility Services has 69 labor contracts representing the majority of its employees. The majority of the labor contracts contain provisions that prohibit work stoppages or strikes and provide for binding arbitration dispute resolution in the event of an extended disagreement.

The Company's principal properties, which are of varying ages and are of different construction types, are believed to be generally in good condition, are well maintained, and are generally suitable and adequate for the purposes for which they are used.

The financial results and data applicable to each of the Company's business segments as well as their financing requirements are set forth in Item 7 – MD&A and Item 8 – Financial Statements and Supplementary Data – Note 13 and Supplementary Financial Information.

The operations of the Company and certain of its subsidiaries are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. The Company believes that it is in substantial compliance with these regulations, except as what may be ultimately determined with regard to the Portland, Oregon, Harbor Superfund Site, which is discussed under Items 1 and 2 – Business and Properties – Construction Materials and Mining – Environmental Matters and in Item 8 – Financial Statements and Supplementary Data – Note 18. There are no pending Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site.

Governmental regulations establishing environmental protection standards are continuously evolving and, therefore, the character, scope, cost and availability of the measures that will permit compliance with these laws or regulations cannot be accurately predicted. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description below.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q, the Company's current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 are available through the Company's Web site as soon as reasonably practicable after the Company has filed such reports with the Securities and Exchange Commission (SEC). The Company's Web site address is www.mdu.com. The information available on the Company's Web site is not part of this annual report on Form 10-K.

ELECTRIC

General Montana-Dakota provides electric service at retail, serving over 117,000 residential, commercial, industrial and municipal customers located in 177 communities and adjacent rural areas as of December 31, 2004. The principal properties owned by Montana-Dakota for use in its electric operations include interests in seven electric generating stations, as further described under System Supply and System Demand, and approximately 3,100 and 4,200 miles of transmission and distribution lines, respectively. 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. For additional information regarding Montana-Dakota's franchises, see Item 7 – MD&A – Prospective Information – Electric. As of December 31, 2004, Montana-Dakota's net electric plant investment approximated $292.9 million.

All of Montana-Dakota's electric properties, 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 trustees, 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.

The electric operations of Montana-Dakota are subject to regulation by the Federal Energy Regulatory Commission (FERC) under provisions of the Federal Power Act with respect to the transmission and sale of power at wholesale in interstate commerce, interconnections with other utilities, the issuance of securities, accounting and other matters. Retail rates, service, accounting and, in certain instances, security issuances are also subject to regulation by the North Dakota Public Service Commission (NDPSC), Montana Public Service Commission (MTPSC), South Dakota Public Utilities Commission (SDPUC) and Wyoming Public Service Commission (WYPSC). The percentage of Montana-Dakota's 2004 electric utility operating revenues by jurisdiction is as follows: North Dakota – 59 percent; Montana – 24 percent; South Dakota – 7 percent and Wyoming – 10 percent.

System Supply and System Demand Through an interconnected electric system, Montana-Dakota serves markets in portions of the following states and major communities – western North Dakota, including Bismarck, Dickinson and Williston; eastern Montana, including Glendive and Miles City; and northern South Dakota, including Mobridge. The interconnected system consists of seven on-line electric generating stations, which have an aggregate turbine nameplate rating attributable to Montana-Dakota's interest of 434,230 kilowatts (kW) and a total summer net capability of 475,000 kW. Montana-Dakota's four principal generating stations are steam-turbine generating units using coal for fuel. The nameplate rating for Montana-Dakota's ownership interest in these four stations (including interests in the Big Stone Station and the Coyote Station aggregating 22.7 percent and 25.0 percent, respectively) is 327,758 kW. Three combustion turbine peaking stations supply the balance of Montana-Dakota's interconnected system electric generating capability. Additionally, Montana-Dakota has contracted to purchase through October 31, 2006, 66,400 kW of participation power annually from Basin Electric Power Cooperative for its interconnected system. Montana-Dakota also has an agreement through December 31, 2020, with the Western Area Power Administration (WAPA) to provide federal hydroelectric power to eligible Native American customers on the Fort Peck Indian Reservation. The program provides a credit to the customers for the portion of their power received from the federal hydroelectric system. The associated summer monthly capability from the WAPA agreement is 2,819 kW.

On January 9, 2004, Montana-Dakota entered into a firm capacity contract with a Midwest utility to purchase capacity during certain months of 2004 to 2006. In addition, on January 9, 2004, Montana-Dakota entered into a firm power contract with the Midwest utility to purchase power during certain months of 2006 to 2010. All capacity and power purchases from these contracts were contingent upon the parties securing transmission service for the delivery of capacity and power to Montana-Dakota's customer load. Transmission service was not secured and no capacity or energy was delivered under this contract in 2004. These agreements expired on December 31, 2004.

On July 15, 2004, Montana-Dakota entered into a firm capacity contract to purchase 15 megawatts of capacity and associated energy for the summer of 2005 and 25 megawatts of capacity and associated energy for the summer of 2006 from a neighboring utility.

On October 25, 2004, Montana-Dakota issued a request for proposal for 70 megawatts to 100 megawatts of firm capacity and associated energy for the period of November 1, 2006 through December 31, 2010. Montana-Dakota is currently in the process of evaluating the responses.

The following table sets forth details applicable to the Company's electric generating stations:

Generating Station	Type	Nameplate Rating (kW)	Summer Capability (kW)	2004 Net Generation (kilowatt-hours in thousands)
North Dakota:				
Coyote*	Steam	103,647	106,750	809,267
Heskett	Steam	86,000	103,780	613,145
Williston	Combustion Turbine	7,800	9,600	(75)**
South Dakota:				
Big Stone*	Steam	94,111	103,240	771,679
Montana:				
Lewis & Clark	Steam	44,000	52,300	345,857
Glendive	Combustion Turbine	75,522	75,500	9,689
Miles City	Combustion Turbine	23,150	23,830	3,311
		434,230	475,000	2,552,873

** Reflects Montana-Dakota's ownership interest.*
*** Station use, to meet Mid-Continent Area Power Pool's (MAPP) accreditation requirements, exceeded generation.*

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland Coal Company (Westmoreland). Contracts with Westmoreland for the Coyote, Heskett and Lewis & Clark stations expire in May 2016, December 2005, and December 2007, respectively. The majority of the Big Stone Station's fuel requirements were met with coal supplied by RAG Coal West, Inc. under a contract that expired on December 31, 2004. On July 14, 2004 and July 22, 2004, Montana-Dakota entered into a three-year coal supply agreement with Kennecott Coal Sale Company (Kennecott) and Arch Coal Sales Company (Arch), respectively, to meet the majority of the Big Stone Station's fuel requirements for the years 2005 to 2007, at contracted pricing. The Kennecott and Arch agreements provide for the purchase during 2005, 2006 and 2007 of 500,000, 1.5 million and 1.3 million tons of coal, respectively, from Kennecott and 1.3 million, 500,000 and 500,000 tons of coal, respectively, from Arch.

The Coyote coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station or 30,000 tons per week, whichever may be the greater quantity at contracted pricing. The maximum quantity of coal during the term of the agreement, and any extension, is 75 million tons. The Heskett coal supply agreement allows for the purchase of coal necessary to supply the coal requirements of the Heskett Station at contracted pricing. The anticipated fuel supply requirement for 2005 is 400,000 tons. The Lewis & Clark coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Lewis & Clark Station, at contracted pricing. Montana-Dakota estimates the coal requirement to be in the range of 250,000 to 325,000 tons per contract year.

During the years ended December 31, 2000, through December 31, 2004, the average cost of coal purchased, including freight, per million British thermal units (Btu) at Montana-Dakota's electric generating stations (including the Big Stone and Coyote stations) in the interconnected system and the average cost per ton, including freight, of the coal purchased was as follows:

Years Ended December 31,	**2004**	2003	2002	2001	2000
Average cost of coal per million Btu	**$ 1.08**	$ 1.04	$ .98	$ .92	$ .94
Average cost of coal per ton	**$15.96**	$15.22	$14.39	$13.43	$13.68

The maximum electric peak demand experienced to date attributable to sales to retail customers on the interconnected system was 470,000 kW in August 2003. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the peak demand growth rate through 2010 will approximate 1.2 percent annually. Montana-Dakota's latest forecast indicates that its kilowatt-hour (kWh) sales growth rate, on a normalized basis, through 2010 will approximate 1.5 percent annually.

Montana-Dakota currently estimates that it has adequate capacity available through existing baseload generating stations, turbine peaking stations and long-term firm purchase contracts to meet the peak demand requirements of its customers through the year 2006. Additional capacity that is needed in 2007, or after, to replace expiring contracts and meet system growth requirements is expected to be met through power contracts and/or building or acquiring an additional 175 megawatts to 200 megawatts of capacity. As part of the North Dakota Industrial

Commission's Lignite Vision 21 project, Montana-Dakota submitted an air quality permit application in May 2004 to construct a 175-megawatt coal-fired plant at Gascoyne, North Dakota. The air permit application is under review at the North Dakota Department of Health (North Dakota Health Department). Montana-Dakota also is involved in the review of other potential projects to replace capacity associated with expiring purchased power contracts and to provide for future growth. The costs of building and/or acquiring the additional generating capacity are expected to be recovered in rates.

Montana-Dakota has major interconnections with its neighboring utilities, all of which are MAPP members. Montana-Dakota considers these interconnections adequate for coordinated planning, emergency assistance, exchange of capacity and energy and power supply reliability.

Through a separate electric system (Sheridan System), Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date and attributable to Montana-Dakota sales to retail consumers on that system was approximately 52,300 kW and occurred in August 2003.

The Sheridan System is supplied through an interconnection with the PacifiCorp transmission system, under an agreement with Black Hills Power and Light Company (Black Hills Power), as part of a power supply contract through December 31, 2006, which allows for the purchase of up to 55,000 kW of capacity annually. On December 30, 2004, Montana-Dakota entered into a power supply contract with Black Hills Power to purchase up to 74,000 kW of capacity annually during the period January 1, 2007 to December 31, 2016.

Regulation and Competition Montana-Dakota is subject to competition in varying degrees, in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas. The restructuring of the electric industry has been slowed due to certain events in the industry. In addition, as a result of competition in electric generation, wholesale power markets have become increasingly competitive and evaluations are ongoing concerning retail competition.

Montana-Dakota is a member of the Midwest Independent Transmission System Operator, Inc. (Midwest ISO). The Midwest ISO is responsible for operational control of the transmission systems of its members. The Midwest ISO agreement permits Montana-Dakota to be a separate transmission pricing zone. The Midwest ISO also provides security center operations and tariff administration.

The Montana legislature passed an electric industry restructuring bill, effective May 2, 1997. The bill provided for full customer choice of electric supplier by July 1, 2002, stranded cost recovery and other provisions. Based on the provisions of such restructuring bill, because Montana-Dakota operates in more than one state, the Company had the option of deferring its transition to full customer choice until 2006. In March 2001, legislation was passed in Montana that delays the restructuring and transition to full customer choice until a time when Montana-Dakota can reasonably implement customer choice in the state of its primary service territory.

In its 1997 legislative session, the North Dakota legislature established an Electric Industry Competition Committee to study over a six-year period the impact of competition on the generation, transmission and distribution of electric energy in North Dakota. In 2003, the committee was expanded and the study was extended for an additional four years. To date, the Committee has made no recommendation regarding restructuring. In 1997, the WYPSC selected a consultant to perform a study on the impact of electric restructuring in Wyoming. The study found no material economic benefits. No further action is pending at this time. The SDPUC has not initiated any proceedings to date concerning retail competition or electric industry restructuring. Federal legislation addressing this issue continues to be discussed.

Although Montana-Dakota is unable to predict the outcome of such regulatory proceedings or legislation, or the extent to which retail competition may occur, Montana-Dakota is continuing to take steps to effectively operate in an increasingly competitive environment. For additional information regarding retail competition, see Item 7 – MD&A – Prospective Information – Electric.

Fuel adjustment clauses contained in North Dakota and South Dakota jurisdictional electric rate schedules allow Montana-Dakota to reflect increases or decreases in fuel and purchased power costs (excluding demand charges) on a timely basis. Expedited rate filing procedures in Wyoming allow Montana-Dakota to timely reflect increases or decreases in fuel and purchased power costs. In Montana (24 percent of electric revenues) such cost changes are includable in general rate filings.

Environmental Matters Montana-Dakota's electric operations are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. Montana-Dakota believes it is in substantial compliance with these regulations.

The U.S. Environmental Protection Agency (EPA) may authorize a state to manage federal programs such as the Federal Clean Air Act (Clean Air Act) and Federal Clean Water Act (Clean Water Act), under approved state programs. This is the case in all the states where Montana-Dakota operates.

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which it operates. Each of these permits has a five-year life. Three permits have expired with a fourth expiring on April 1, 2005. Montana-Dakota has submitted applications for renewal on all four permits within the required time frames, and as a result, all the expired permits remain valid. State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities located on the Yellowstone and Missouri Rivers. These permits also have a five-year life with the first permit expiring on November 30, 2005. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and U.S. Army Corps of Engineers (Army Corps) permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary, and the permits are renewed as necessary.

Montana-Dakota's electric operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the Resource Conservation and Recovery Act (RCRA). Montana-Dakota routinely handles polychlorinated biphenyls (PCBs) from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota did not incur any material environmental expenditures in 2004 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007. For matters involving Montana-Dakota and the North Dakota Health Department and a related matter involving the Dakota Resource Council, see Item 3 – Legal Proceedings.

NATURAL GAS DISTRIBUTION

General Montana-Dakota sells natural gas at retail, serving over 223,000 residential, commercial and industrial customers located in 142 communities and adjacent rural areas as of December 31, 2004, and provides natural gas transportation services to certain customers on its system. Great Plains sells natural gas at retail, serving over 22,000 residential, commercial and industrial customers located in 19 communities and adjacent rural areas as of December 31, 2004, and provides natural gas transportation services to certain customers on its system. These services for the two public utility divisions are provided through distribution systems aggregating approximately 5,200 miles. 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. For additional information regarding Montana-Dakota's and Great Plains' franchises, see Item 7 – MD&A – Prospective Information – Natural gas distribution. As of December 31, 2004, Montana-Dakota's and Great Plains' net natural gas distribution plant investment approximated $151.6 million.

All of Montana-Dakota's natural gas distribution properties, 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 trustees, 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.

The natural gas distribution operations of Montana-Dakota are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC regarding retail rates, service, accounting and, in certain instances, security issuances. The natural gas distribution operations of Great Plains are subject to regulation by the NDPSC and Minnesota Public Utilities Commission (MPUC) regarding retail rates, service, accounting and, in certain instances, security issuances. The percentage of Montana-Dakota's and Great Plains' 2004 natural gas utility operating revenues by jurisdiction is as follows: North Dakota – 40 percent; Minnesota – 10 percent; Montana – 25 percent; South Dakota – 19 percent and Wyoming – 6 percent.

System Supply, System Demand and Competition Montana-Dakota and Great Plains serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of the following states and major communities – North Dakota, including Bismarck, Dickinson, Wahpeton, Williston, Minot and Jamestown; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; western and north-central South Dakota, including Rapid City, Pierre and Mobridge; and northern Wyoming, including Sheridan. These markets are highly seasonal and sales volumes depend largely on the weather, the effects of which are mitigated in certain jurisdictions by a Distribution Delivery Stabilization Mechanism discussed in Regulatory Matters.

The following table reflects this segment's natural gas sales, natural gas transportation volumes and degree days as a percentage of normal during the last five years:

Years Ended December 31,	2004*	2003*	2002*	2001*	2000**
			Mdk (thousands of decatherms)		
Sales:					
Residential	**20,303**	21,498	21,893	20,087	20,554
Commercial	**14,598**	15,537	16,044	14,661	14,590
Industrial	**1,706**	1,537	1,621	1,731	1,451
Total	**36,607**	38,572	39,558	36,479	36,595
Transportation:					
Commercial	**1,702**	1,528	1,849	1,847	2,067
Industrial	**12,154**	12,375	11,872	12,491	12,247
Total	**13,856**	13,903	13,721	14,338	14,314
Total Throughput	**50,463**	52,475	53,279	50,817	50,909
Degree days*** (% of normal)	**90.7%**	97.3%	101.1%	94.5%	100.4%

* *Includes Great Plains.*
** *Sales and transportation volumes for Great Plains are for the period July through December 2000. Degree days exclude Great Plains.*
*** *Degree days are a measure of daily temperature-related demand for energy for heating.*

Competition in varying degrees exists between natural gas and other fuels and forms of energy. Montana-Dakota and Great Plains have established various natural gas transportation service rates for their distribution businesses to retain interruptible commercial and industrial loads. Certain of these services include transportation under flexible rate schedules whereby Montana-Dakota's and Great Plains' interruptible customers can avail themselves of the advantages of open access transportation on regional transmission pipelines, including the system of Williston Basin, Northern Natural Gas Company and Viking Gas Transmission Company. These services have enhanced Montana-Dakota's and Great Plains' competitive posture with alternate fuels, although certain of Montana-Dakota's customers have bypassed the respective distribution systems by directly accessing transmission pipelines located within close proximity. These bypasses did not have a material effect on results of operations.

Montana-Dakota and Great Plains obtain their system requirements directly from producers, processors and marketers. Such natural gas is supplied by a portfolio of contracts specifying market-based pricing, and is transported under transportation agreements by Williston Basin, Kinder Morgan, Inc., South Dakota Intrastate Pipeline Company, Northern Border Pipeline Company, Viking Gas Transmission Company and Northern Natural Gas Company to provide firm service to their customers. Montana-Dakota has also contracted with Williston Basin to provide firm storage services that enable Montana-Dakota to meet winter peak requirements as well as allow it to better manage its natural gas costs by purchasing natural gas at more uniform daily volumes throughout the year. Demand for natural gas, which is a widely traded commodity, is sensitive to seasonal heating and industrial load requirements as well as changes in market price. Montana-Dakota and Great Plains believe that, based on regional supplies of natural gas and the pipeline transmission network currently available through its suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next five years.

Regulatory Matters On September 7, 2004, Great Plains filed an application with the MPUC for a natural gas rate increase. Great Plains had requested a total of $1.4 million annually or 4.0 percent above current rates. Great Plains also requested an interim increase of $1.4 million annually. On November 23, 2004, the MPUC issued an Order setting interim rates of $1.4 million annually effective with service rendered on or after January 10, 2005, subject to refund. A final order from the MPUC is expected in late 2005.

On June 7, 2004, Montana-Dakota filed an application with the SDPUC for a natural gas rate increase for the Black Hills service area. Montana-Dakota requested a total of $1.3 million annually or 2.2 percent above current rates. On November 15, 2004, Montana-Dakota and the SDPUC Staff filed a Settlement Stipulation with the SDPUC agreeing to an increase of $670,000 annually, or 1.4 percent. On November 30, 2004, the SDPUC approved the Settlement Stipulation effective with service rendered on or after December 1, 2004.

On April 1, 2004, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total of $1.5 million annually or 1.8 percent above current rates. On January 14, 2005, Montana-Dakota and the Montana Consumer Counsel filed a Stipulation with the MTPSC agreeing to an increase of $125,000 annually to be effective with service rendered on or after February 1, 2005. On January 25, 2005, the MTPSC passed a Motion approving the Stipulation.

Montana-Dakota's and Great Plains' retail natural gas rate schedules contain clauses permitting monthly adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current regulatory practices allow Montana-Dakota and Great Plains to recover increases or refund decreases in such costs within a period ranging from 24 months to 28 months from the time such costs are paid.

Montana-Dakota's North Dakota and South Dakota–Black Hills area gas tariffs contain a Distribution Delivery Stabilization Mechanism applicable to the firm rate schedules to correct for the over/under collection of distribution delivery charge revenues due to weather fluctuations during the billing period from November 1 through May 1.

Environmental Matters Montana-Dakota's and Great Plains' natural gas distribution operations are subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. Montana-Dakota and Great Plains believe they are in substantial compliance with those regulations.

Montana-Dakota's and Great Plains' operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Montana-Dakota and Great Plains routinely handle PCBs from their natural gas operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota and Great Plains did not incur any material environmental expenditures in 2004 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007.

UTILITY SERVICES

General Utility Services specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling, and the manufacture and distribution of specialty equipment. These services are provided to utilities and large manufacturing, commercial, government and institutional customers.

Construction and maintenance crews are active year round. However, activity in certain locations may be seasonal in nature due to the effects of weather.

Utility Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2004, Utility Services owned or leased offices in 14 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops. At December 31, 2004, Utility Services' net plant investment was approximately $43.3 million.

Utility Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts and the estimated value of future services that it expects to provide under other master agreements. The backlog at December 31, 2004, was approximately $238 million compared to $148 million at December 31, 2003. Utility Services expects to complete a significant amount of this backlog during the year ending December 31, 2005. Due to the nature of its contractual arrangements, in many instances Utility Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather Utility Services is committed to perform these services if and to the extent requested by the customer. The customer is, however, obligated to obtain these services from Utility Services if they are not performed by the customer's employees. Therefore, there can be no assurance as to the customer's requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

This industry is experiencing a shortage of lineworkers in certain areas. Utility Services works with the National Electrical Contractors Association and the IBEW on hiring and recruiting qualified lineworkers.

Competition Utility Services operates in a highly competitive business environment. Most of Utility Services' work is obtained on the basis of competitive bids or by negotiation of either cost plus or fixed price contracts. The workforce and equipment are highly mobile, providing greater flexibility in the size and location of Utility Services' market area. Competition is based primarily on price and reputation for quality, safety and reliability. The size and area location of the services provided as well as the state of the economy will be factors in the number of competitors that Utility Services will encounter on any particular project. Utility Services believes that the diversification of the services it provides, the market it serves throughout the United States and the management of its workforce will enable it to effectively operate in this competitive environment.

Utilities and independent contractors represent the largest customer base for this segment. Accordingly, utility and sub-contract work accounts for a significant portion of the work performed by Utility Services and the amount of construction contracts is dependent to a certain extent on the level and timing of maintenance and construction programs undertaken by customers. Utility Services relies on repeat customers and strives to maintain successful long-term relationships with these customers.

Environmental Matters Utility Services' operations are subject to regulation customary for the industry, including federal, state and local environmental compliance. Utility Services believes it is in substantial compliance with these regulations.

The nature of Utility Services' operations is such that few, if any, environmental permits are required. Operational convenience supports the use of petroleum storage tanks in several locations, which are permitted under state programs authorized by the EPA. Utility Services currently has no ongoing remediation related to releases from petroleum storage tanks. Utility Services operations are conditionally exempt small-quantity waste generators, subject to minimal regulation under the RCRA. Federal permits for specific construction and maintenance jobs that may require these permits are typically obtained by the hiring entity, and not by Utility Services.

Utility Services did not incur any material environmental expenditures in 2004 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007.

PIPELINE AND ENERGY SERVICES

General Williston Basin, the principal regulated business of WBI Holdings, owns and operates over 3,700 miles of transmission, gathering and storage lines and owns or leases and operates 26 compressor stations located in the states of Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields located in Montana and Wyoming provide storage services to local distribution companies, producers, natural gas marketers and others, and serve to enhance system deliverability. Williston Basin's system is strategically located near five natural gas producing basins, making natural gas supplies available to Williston Basin's transportation and storage customers. The system has 11 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. At December 31, 2004, Williston Basin's net plant investment was approximately $215.8 million. Under the Natural Gas Act, as amended, Williston Basin is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters.

WBI Holdings, through its nonregulated pipeline business, owns and operates gathering facilities in Colorado, Kansas, Montana and Wyoming. A one-sixth interest in the assets of various offshore gathering pipelines and associated onshore pipeline and related processing facilities also is owned by WBI Holdings. These facilities include over 1,600 miles of field gathering lines and 79 owned or leased compression facilities, some of which interconnect with Williston Basin's system. In addition, WBI Holdings provides installation sales and/or leasing of alternate energy delivery systems, primarily propane air facilities, as well as providing energy efficiency product sales and installation services to large end users.

WBI Holdings, through its energy services businesses, provides natural gas purchase and sales services to local distribution companies, producers, other marketers and a limited number of large end users, primarily using natural gas produced by the Company's natural gas and oil production segment. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. WBI Holdings currently estimates that it can adequately meet the requirements of these contracts. WBI Holdings transacts a significant portion of its business in the northern Great Plains and Rocky Mountain regions of the United States.

Another energy services business owned by WBI Holdings is Innovatum, Inc. (Innovatum), a cable and pipeline magnetization and locating company. Innovatum provides products and services that assist the natural gas and oil and telecommunication industries with accurate location and tracking of submerged pipelines and cables on a worldwide basis. Additionally, Innovatum manufactures and resells a line of terrestrial, hand-held locators that are used for locating and identifying underground objects. Innovatum has 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.

System Demand and Competition Williston Basin competes with several pipelines for its customers' transportation, storage and gathering business and at times may discount rates in an effort to retain market share. However, the strategic location of Williston Basin's system near five natural gas producing basins and the availability of underground storage and gathering services provided by Williston Basin and affiliates along with interconnections with other pipelines serve to enhance Williston Basin's competitive position.

Although a significant portion of Williston Basin's firm customers, which include Montana-Dakota, serve relatively secure residential and commercial end users, virtually all have some price-sensitive end users that could switch to alternate fuels.

Williston Basin transports substantially all of Montana-Dakota's natural gas, utilizing firm transportation agreements, which at December 31, 2004, represented 68 percent of Williston Basin's currently subscribed firm transportation capacity. In October 2001, Montana-Dakota executed a firm transportation agreement with Williston Basin for a term of five years expiring in June 2007. In addition, in July 1995, Montana-Dakota entered into a 20-year contract with Williston Basin to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements.

System Supply Williston Basin's underground storage facilities have a certificated storage capacity of approximately 353 billion cubic feet (Bcf), including 193 Bcf of working gas capacity, 85 Bcf of cushion gas and 75 Bcf of native gas. The native gas includes an estimated 29 Bcf of recoverable gas. Williston Basin's storage facilities enable its customers to purchase natural gas at more uniform daily volumes throughout the year and, thus, facilitate meeting winter peak requirements.

Natural gas supplies from certain traditional regional sources have declined during the past several years and such declines are anticipated to continue. As a result, Williston Basin anticipates that a potentially significant amount of the future supply needed to meet its customers' demands will come from non-traditional, off-system sources. The Company's coalbed natural gas assets in the Powder River Basin are expected to meet some of these supply needs. For additional information regarding coalbed natural gas legal proceedings, see Item 3 – Legal Proceedings and Item 7 – MD&A – Risk Factors and Cautionary Statements that May Affect Future Results – Environmental and Regulatory Risks. Williston Basin expects to facilitate the movement of these supplies by making available its transportation and storage services. Williston Basin will continue to look for opportunities to increase transportation, gathering and storage services through system expansion and/or other pipeline interconnections or enhancements that could provide substantial future benefits.

Regulatory Matters and Revenues Subject to Refund 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. In July 2003, the FERC issued its Order on Initial Decision. The Order on the 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. In August 2003, Williston Basin requested 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 May 11, 2004, the FERC issued an Order on Rehearing and Compliance and Remanding Certain Issues for Hearing (Order on Rehearing). The Order on Rehearing denied rehearing on all of the issues addressed by Williston Basin in its August 2003 request for rehearing except for the issue of the proper rate to utilize for transmission system negative salvage expenses. In addition, the FERC remanded the issues regarding certain service and annual demand quantity restrictions to an ALJ for resolution. On June 14, 2004, Williston Basin requested clarification of a few of the issues addressed in the Order on Rehearing including determinations associated with cost of service and cost allocation, as discussed in the FERC's Order on Rehearing. On June 14, 2004, Williston Basin also made its filing to comply with the requirements of the various FERC orders in this proceeding. Williston Basin is awaiting a decision from the FERC on Williston Basin's compliance filing and clarification request but is unable to predict the timing of the FERC's decision. Williston Basin participated in a hearing before the ALJ in early January 2005, regarding the matters remanded to the ALJ by the FERC in its Order on Rehearing and an order on these matters is expected in 2005.

A liability has 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 the liability is adequate based on its assessment of the ultimate outcome of the proceeding.

Environmental Matters WBI Holdings' pipeline and energy services' operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. WBI Holdings believes it is in substantial compliance with those regulations.

The ongoing operations of Williston Basin and Bitter Creek Pipelines, LLC (Bitter Creek), an indirect wholly owned subsidiary of WBI Holdings, are subject to the Clean Air Act and the Clean Water Act. Administration of many provisions of these laws has been delegated to the states where Williston Basin and Bitter Creek operate, and permit terms vary. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed as necessary.

Detailed environmental assessments are included in the FERC's permitting processes for both the construction and abandonment of Williston Basin's natural gas transmission pipelines and storage facilities.

WBI Holdings' pipeline and energy services' operations did not incur any material environmental expenditures in 2004 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007.

NATURAL GAS AND OIL PRODUCTION

General Fidelity Exploration & Production Company (Fidelity), a direct wholly owned subsidiary of WBI Holdings, 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. Natural gas production from operated properties was 74 percent of total natural gas production for the year ended December 31, 2004.

Fidelity continues to seek additional reserve and production growth opportunities through the direct acquisition of producing properties, acquisition of exploration and development leaseholds and acreage and through exploratory drilling opportunities, as well as development of its existing properties. Future growth is dependent upon its success in these endeavors.

Operating Information Information on natural gas and oil production, average realized prices and production costs per net equivalent Mcf related to natural gas and oil interests for 2004, 2003 and 2002, are as follows:

	2004	2003	2002
Natural Gas:			
Production (MMcf)	**59,750**	54,727	48,239
Average realized price (including hedges)	**$ 4.69**	$ 3.90	$ 2.72
Average realized price (excluding hedges)	**$ 4.90**	$ 4.28	$ 2.54
Oil:			
Production (000's of barrels)	**1,747**	1,856	1,968
Average realized price (including hedges)	**$34.16**	$27.25	$22.80
Average realized price (excluding hedges)	**$37.75**	$28.42	$23.26
Production costs, including taxes, per net equivalent Mcf:			
Lease operating costs	**$ .47**	$ .48	$ .46
Gathering and transportation	**.17**	.22	.20
Production and property taxes	**.32**	.32	.21
	$ .96	$ 1.02	$ .87

Well and Acreage Information Gross and net productive well counts and gross and net developed and undeveloped acreage related to interests at December 31, 2004, are as follows:

	Gross	Net
Productive Wells:		
Natural Gas	**2,975**	**2,419**
Oil	**2,223**	**123**
Total	**5,198**	**2,542**
Developed Acreage (000's)	**791**	**350**
Undeveloped Acreage (000's)	**1,391**	**614**

Exploratory and Development Wells The following table reflects activities relating to Fidelity's natural gas and oil wells drilled and/or tested during 2004, 2003 and 2002:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2004	**1**	**4**	**5**	**230**	**20**	**250**	**255**
2003	10	2	12	274	2	276	288
2002	4	–	4	201	–	201	205

At December 31, 2004, there were 147 gross wells in the process of drilling or under evaluation, 144 of which were development wells and three of which were exploratory wells. These wells are not included in the previous table. Fidelity expects to complete drilling and testing the majority of these wells within the next 12 months.

Competition The natural gas and oil industry is highly competitive. Fidelity competes with a substantial number of major and independent natural gas and oil companies in acquiring producing properties and new leases for future exploration and development, and in securing the equipment and expertise necessary to develop and operate its properties. Many of Fidelity's competitors have greater financial and operational resources than Fidelity.

Environmental Matters WBI Holdings' natural gas and oil production operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. WBI Holdings believes it is in substantial compliance with these regulations.

The ongoing operations of Fidelity are subject to the Clean Water Act and other federal and state environmental regulations. Administration of many provisions of the federal laws has been delegated to the states where Fidelity operates, and permit terms vary. Some permits have terms ranging from one to five years and others have no expiration date.

Some of Fidelity's operations are subject to Section 404 of the Clean Water Act as administered by the Army Corps. Section 404 permits are required for operations that may affect waters of the United States, including operations in wetlands. The expiration dates of these permits also vary, with five years generally being the longest term.

Detailed environmental assessments and/or environmental impact statements under federal and state laws are required as part of the permitting process incident to commencement of drilling and production operations as well as in abandonment proceedings.

In connection with the development of coalbed natural gas properties, certain capital expenditures were incurred related to water handling. For 2004, capital expenditures for water handling in compliance with current laws and regulations were approximately $400,000 and are estimated to be less than $3.5 million in 2005 and less than $3.0 million per year for 2006 and 2007. For information regarding coalbed natural gas legal proceedings, see Item 3 – Legal Proceedings, Item 7 – MD&A – Risk Factors and Cautionary Statements that May Affect Future Results – Environmental and Regulatory Risks and Item 8 – Financial Statements and Supplementary Data – Note 18.

Reserve Information Fidelity's recoverable proved developed and undeveloped natural gas and oil reserves approximated 453.2 Bcf and 17.1 million barrels, respectively, at December 31, 2004.

For additional information related to natural gas and oil interests, see Item 8 – Financial Statements and Supplementary Data – Note 1 and Supplementary Financial Information.

CONSTRUCTION MATERIALS AND MINING

General Knife River operates construction materials and mining businesses in Alaska, California, Hawaii, Idaho, Iowa, Minnesota, Montana, North Dakota, Oregon, Texas and Wyoming. These operations mine, process and sell construction aggregates (crushed stone, sand and gravel) and supply ready-mixed concrete for use in most types of construction, including homes, schools, shopping centers, office buildings and industrial parks as well as roads, freeways and bridges.

In addition, certain operations produce and sell asphalt for various commercial and roadway applications. Although not common to all locations, other products include the sale of cement, various finished concrete products and other building materials and related construction services.

During 2004, the Company acquired several construction materials and mining businesses with operations in Hawaii, Idaho, Iowa and Minnesota. None of these acquisitions were individually material to the Company.

Knife River's construction materials business has continued to grow since its first acquisition in 1992. Knife River continues to investigate the acquisition of other construction materials properties, particularly those relating to sand and gravel aggregates and related products such as ready-mixed concrete, asphalt and various finished aggregate products.

Knife River's construction materials business has benefited from the Transportation Equity Act for the 21st Century (TEA-21). TEA-21 expired on September 30, 2003; however, funding is currently being provided under an extension of TEA-21 that expires on May 31, 2005. Although it is difficult to predict the outcome of legislation regarding federal highway construction funding that is anticipated to replace TEA-21, Knife River expects replacement funding to be equal to or higher than TEA-21.

The construction materials business had approximately $426 million in backlog at December 31, 2004, compared to $332 million at December 31, 2003. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2005.

Competition Knife River's construction materials products are marketed under highly competitive conditions. Because there are generally no measurable product differences in the market areas in which Knife River conducts its construction materials businesses, price is the principal competitive force to which these products are subject, with service, delivery time and proximity to the customer also being significant factors. The number and size of competitors varies in each of Knife River's principal market areas and product lines.

The demand for construction materials products is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials activity in certain locations may be seasonal in nature due to the effects of weather. The key economic factors affecting product demand are changes in the level of local, state and federal governmental spending, general economic conditions within the market area that influence both the commercial and private sectors, and prevailing interest rates.

Knife River is not dependent on any single customer or group of customers for sales of its construction materials products, the loss of which would have a materially adverse effect on its construction materials businesses.

Reserve Information Reserve estimates are calculated based on the best available data. These data are collected from drill holes and other subsurface investigations, as well as investigations of surface features like mine highwalls and other exposures of the aggregate reserves. Mine plans, production history and geologic data also are utilized to estimate reserve quantities. Most acquisitions are made of mature businesses with established reserves, as distinguished from exploratory type properties.

Estimates are based on analyses of the data described above by experienced mining engineers, operating personnel and geologists. Property setbacks and other regulatory restrictions and limitations are identified to determine the total area available for mining. Data described above are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by simply applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

Topography associated with the hard rock reserves is typically much more diverse. Therefore, using available data, a final topography map is created and computer software is utilized to compute the volumes between the existing and final topographies. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 2 tons per cubic yard in the ground is used for hard rock quarries.

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 1.1 billion tons of the 1.3 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that we expect will be permitted for mining under current regulatory requirements. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life (years remaining) anticipates, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves. The data used to calculate the remaining reserves may require revisions in the future to account for changes in customer requirements and unknown geological occurrences. The years remaining were calculated by dividing remaining reserves by current year sales. Actual useful lives of these reserves will be subject to, among other things, fluctuations in customer demand, customer specifications, geological conditions and changes in mining plans.

The following table sets forth details applicable to the Company's aggregate reserves under ownership or lease as of December 31, 2004, and sales as of and for the years ended December 31, 2004, 2003 and 2002:

Production Area	Number of Sites (Crushed Stone) owned	Number of Sites (Crushed Stone) leased	Number of Sites (Sand & Gravel) owned	Number of Sites (Sand & Gravel) leased	Tons Sold (000's) 2004	Tons Sold (000's) 2003	Tons Sold (000's) 2002	Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Central MN	–	1	52	60	**6,429**	6,265	6,236	112,668	2005-2028	18
Portland, OR	1	4	5	3	**5,821**	4,610	4,186	271,826	2005-2055	47
Northern CA	1	–	7	1	**3,699**	3,907	3,430	58,269	2046	16
Southwest OR	3	6	11	3	**3,405**	3,360	2,812	103,990	2005-2031	31
Eugene, OR	3	3	4	2	**2,003**	1,442	2,724	185,651	2006-2046	93
Hawaii	–	6	–	–	**2,460**	2,134	2,688	77,170	2011-2037	31
Central MT	–	–	5	1	**2,555**	2,667	2,463	37,440	2011-2023	15
Anchorage, AK	–	–	1	–	**1,473**	1,610	1,719	23,280	N/A	16
Northwest MT	–	–	8	5	**1,810**	1,413	1,260	29,886	2005-2020	17
Southern CA	–	2	–	–	**518**	1,945	1,247	95,809	2035	185
Bend, OR / Boise, ID	1	2	4	1	**1,678**	857	1,030	78,454	2010-2012	47
Northern MN	2	–	21	20	**853**	873	559	33,825	2005-2016	40
Northern IA / Southern MN	18	10	8	26	**1,370**	–	–	70,838	2005-2017	52
North / South Dakota	–	–	2	59	**965**	704	–	59,192	2005-2031	61
Eastern TX	–	3	–	3	**1,067**	449	–	18,215	2005-2012	17
Casper, WY	–	–	–	1	**291**	172	61	985	2006	3
Sales from other sources					**7,047**	6,030	4,663	–		
					43,444	38,438	35,078	1,257,498		

The 1.3 billion tons of estimated aggregate reserves at December 31, 2004, is comprised of 562 million tons that are owned and 696 million tons that are leased. The leases have various expiration dates ranging from 2005 to 2055. Approximately 58 percent of the tons under lease have lease expiration dates of 20 years or more. The weighted average years remaining on all leases containing estimated probable aggregate reserves is approximately 23 years, including options for renewal that are at Knife River's discretion. Based on 2004 sales from leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 46 years.

The following table summarizes Knife River's aggregate reserves at December 31, 2004, 2003 and 2002 and reconciles the changes between these dates:

	2004	2003	2002
		(000's of tons)	
Aggregate Reserves:			
Beginning of year	**1,181,413**	1,110,020	1,065,330
Acquisitions	**115,965**	109,362	72,808
Sales volumes*	**(36,397)**	(32,408)	(30,415)
Other	**(3,483)**	(5,561)	2,297
End of year	**1,257,498**	1,181,413	1,110,020

** Excludes sales from other sources.*

Lignite Deposits The Company has lignite deposits and leases at its former Gascoyne Mine site in North Dakota. These lignite deposits are currently not being mined and are not associated with an operating mine. The 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, 2004, Knife River had under ownership or lease, deposits of approximately 11.4 million tons of recoverable lignite coal.

Environmental Matters Knife River's construction materials and mining operations are subject to regulation customary for such operations, including federal, state and local environmental compliance and reclamation regulations. Except as what may be ultimately determined with regard to the Portland, Oregon, Harbor Superfund Site issue described below, Knife River believes it is in substantial compliance with these regulations.

Knife River's asphalt and ready-mixed concrete manufacturing plants and aggregate processing plants are subject to Clean Air Act and Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these laws. In the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to RCRA as it applies to underground storage tanks and the management of petroleum hydrocarbon products and wastes. These programs also have generally been delegated to the state and local authorities in the states where Knife River operates. No specific permits are required but Knife River's facilities must comply with requirements for managing petroleum hydrocarbon products and wastes.

Some Knife River activities are directly regulated by federal agencies. For example, gravel bar skimming and deep water dredging operations are subject to provisions of the Clean Water Act that are administered by the Army Corps. Knife River operates nine gravel bar skimming operations and one deep water dredging operation in Oregon, all of which are subject to Army Corps permits as well as state permits. The expiration dates of these permits vary, with five years generally being the longest term. None of these in-water mining operations are included in Knife River's aggregate reserve numbers.

Knife River's operations also are occasionally subject to the Endangered Species Act (ESA). For example, land use regulations often require environmental studies, including wildlife studies before a permit may be granted for a new or expanded mining facility. If endangered species or their habitats are identified, ESA requirements for protection, mitigation or avoidance apply. Endangered species protection requirements are usually included as part of land use permit conditions. Typical conditions include avoidance, setbacks, restrictions on operations during certain times of the breeding or rearing season, and construction or purchase of mitigation habitat. Knife River's operations also are subject to state and federal cultural resources protection laws when new areas are disturbed for mining operations. Mining permit applications generally require that areas proposed for mining be surveyed for cultural resources. If any are identified, they must be protected or managed in accordance with regulatory agency requirements.

The most challenging environmental permit requirements are usually associated with new mining operations, although requirements vary widely from state to state and even within states. In some areas, land use regulations and associated permitting requirements are minimal. However, some states and local jurisdictions have very demanding requirements for permitting new mines. Environmental impact reports are sometimes required before a mining permit application can even be considered for approval. These reports can take up to several years to complete. The report can include projected impacts of the proposed project on air and water quality, wildlife, noise levels, traffic, scenic vistas, and other environmental factors. The reports generally include suggested actions to mitigate the projected adverse impacts.

Provisions for public hearings and public comments are usually included in mine permit application review procedures in the counties where Knife River operates. After taking into account environmental, mine plan and reclamation information provided by the permittee as well as comments from the public and other regulatory agencies, the local authority approves or denies the permit application. Denial is rare but permits for mining often include conditions that must be addressed by the permittee. Conditions may include property line setbacks, reclamation requirements, environmental monitoring and reporting, operating hour restrictions, financial guarantees for reclamation, and other requirements intended to protect the environment or address concerns submitted by the public or other regulatory agencies.

Despite the challenges, Knife River has been successful in obtaining mining permit approvals so that sufficient permitted reserves are available to support its operations. This often requires considerable advanced planning to ensure sufficient time is available to complete the permitting process before the newly permitted reserve is needed to support Knife River's operations.

Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the Surface Mining Control and Reclamation Act (SMCRA), as well as the North Dakota Surface Mining Act. Much of the property formerly occupied by the mine remains under reclamation bond pending completion of the 10-year revegetation liability period under SMCRA.

Knife River did not incur any material environmental expenditures in 2004 and, except as what may be ultimately determined with regard to the issue described below, Knife River does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007.

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.

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.

INDEPENDENT POWER PRODUCTION

General Centennial Resources owns, builds and operates electric generating facilities in the United States and has investments in domestic and international natural resource-based projects. Electric capacity and energy produced at its power plants are sold primarily under mid- and long-term contracts to nonaffiliated entities.

Competition Centennial Resources encounters competition in the development of new electric generating plants and the acquisition of existing generating facilities, as well as operation and maintenance services. Competitors include other non-utility generators, regulated utilities, nonregulated subsidiaries of regulated utilities and other energy service companies as well as financial investors. Competition for power sales agreements may reduce power prices in certain markets. Factors for competing in the power production industry include having a balanced portfolio of generating assets, fuel types, customers and power sales agreements and maintaining low production costs.

Domestic

Centennial Power, Inc. (Centennial Power), an indirect wholly owned subsidiary of the Company, owns 213 megawatts of natural gas-fired electric generating facilities (Brush Generating Facility) near Brush, Colorado. These facilities were purchased in November 2002. Ninety-five percent of the Brush Generating Facility's output is sold to Public Service of Colorado (PSCO), a wholly owned subsidiary of Xcel Energy, under two power purchase contracts that expire in October 2005 and September 2012, respectively. The Brush Generating Facility is operated by Colorado Energy Management (CEM), an indirect wholly owned subsidiary of the Company. PSCO is under contract to supply natural gas to the Brush Generating Facility during the terms of the power purchase contracts.

Centennial Power owns a 66.6-megawatt wind-powered electric generating facility located in the San Gorgonio Pass, northwest of Palm Springs, California. This facility was purchased in January 2003. The facility sells all of its output under a contract with the California Department of Water Resources, which expires in September 2011. SeaWest Wind Power, Inc. (SeaWest) is under a contract to operate the facility. The contract with SeaWest expires in October 2013.

On September 28, 2004, Centennial Resources, through wholly owned subsidiaries, acquired a 50-percent ownership in a 310-megawatt natural gas-fired electric generating facility (Hartwell Generating Facility). This facility is located in Hartwell, Georgia. The Hartwell Generating Facility sells its output under a power purchase agreement with Oglethorpe Power Corporation (Oglethorpe) that expires in May 2019. American National Power, a wholly owned subsidiary of International Power of the United Kingdom, holds the remaining 50-percent ownership interest and is the operating partner for the facility.

On April 16, 2004, Centennial Resources purchased CEM. CEM provides analysis, design, construction, refurbishment, and operation and maintenance services to independent power producers. CEM is headquartered in Lafayette, Colorado. CEM provides operations and maintenance services for third-party customers owning approximately 510 megawatts of generating capacity at January 1, 2005. The operation and maintenance contracts have expirations ranging from January 2006 to June 2009.

Environmental Matters Centennial Power has several operations that require federal and state environmental permits. The Brush Generating Facility and the Hartwell Generating Facility are subject to federal, state and local laws and regulations providing for air, water and solid waste pollution control; state facility-siting regulations; zoning and planning regulations of certain state and local authorities; federal health and safety regulations and state hazard communication standards. Centennial Power believes it is in substantial compliance with these regulations.

The Brush Generating Facility has a Title V Operating Permit issued by the state for a period of five years under a program approved by the EPA. The facility also has a water discharge agreement to release process water to the City of Brush. This agreement has no specific termination date as long as the Brush Generating Facility is operating in compliance with the agreement.

The Hartwell Generating Facility has a Title V Operating Permit issued by the state for a period of five years under a program approved by the EPA. Centennial Power believes it is in substantial compliance with these regulations.

The Mountain View wind-powered electric generating facility has obtained necessary siting authority and federal land leases for its operations. It has minor requirements related to water management and spill control under the Clean Water Act administered by the state.

Centennial Power did not incur any material environmental expenditures in 2004 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007 in connection with its existing operations.

Other Centennial Resources is constructing a 116-megawatt coal-fired electric generating facility near Hardin, Montana. A power sales agreement with Powerex Corp., a subsidiary of BC Hydro, has been secured for the entire output of the plant for a term expiring October 31, 2008, with the purchaser having an option for a two-year extension. The projected on-line date for this plant is late 2005. For additional information regarding this plant, see Item 7 – MD&A – Prospective Information – Independent power production.

International

MDU Brasil Ltda. (MDU Brasil), an indirect wholly owned Brazilian subsidiary of the Company, is party to a joint venture agreement with a Brazilian firm under which the parties formed MPX Participacoes, Ltda. (MPX) to develop electric generation and transmission, steam generation and coal mining projects in Brazil. MDU Brasil has a 49-percent interest in MPX. MPX, through a wholly owned subsidiary, owns and operates a 220-megawatt natural gas-fired electric generating facility (Termoceara Generating Facility) in the Brazilian state of Ceara. The first phase of the Termoceara Generating Facility entered commercial operations in July 2002. The second phase entered commercial operations in January 2003. Petrobras, the Brazilian state-controlled energy company, entered into a contract to purchase all of the capacity and market all of the energy from the Termoceara Generating Facility. The first phase of the electric power sales contract with Petrobras for 110 megawatts expires in November 2007 and the portion of the contract for the remaining 110 megawatts expires in May 2008. Petrobras also is under contract to supply natural gas to the Termoceara Generating Facility during the term of the electric power sales contract. This natural gas supply contract is renewable by a wholly owned subsidiary of MPX for an additional 13 years. The Termoceara Generating Facility generates electricity based upon economic dispatch and available gas supplies. Under current conditions, including, in particular, existing constraints in the region's gas supply infrastructure, the Company does not expect the facility to generate a significant amount of energy at least through 2006. For information regarding any potential effect from recent events related to the Brazilian electric power sales contract, see Item 8 – Financial Statements and Supplementary Data – Note 2.

On February 26, 2004, Centennial Energy Resources International, Inc. (Centennial International), an indirect wholly owned subsidiary of the Company, acquired 49.99 percent of Carib Power Management LLC (Carib Power). Carib Power, through a wholly owned subsidiary, owns a 225-megawatt natural gas-fired electric generating facility located in Trinidad and Tobago (Trinity Generating Facility). The Trinity Generating Facility sells its output to the Trinidad and Tobago Electric Commission (T&TEC), the governmental entity responsible for the transmission, distribution and administration of electrical power to the national electrical grid of Trinidad and Tobago. The power purchase agreement expires in September 2029. T&TEC also is under contract to supply natural gas to the Trinity Generating Facility during the term of the power purchase contract.

For additional information regarding international operations, see Item 7 – MD&A – Risk Factors and Cautionary Statements that May Affect Future Results – Risks Relating to Foreign Operations.

Environmental Matters The Termoceara Generating Facility is subject to all Brazilian federal and state environmental statutes. IBAMA, the Brazilian government regulatory agency or Brazilian Environment Institute, oversees all environmental issues within Brazil. SEMACE, the state of Ceara regulatory body or state of Ceara Environmental Superintendency, annually issues an operating license to MPX. MPX maintains and must annually renew its operating license that is granted by SEMACE. SEMACE requires air and water monitoring on a regular basis. ANEEL, the Brazilian federal electric regulatory body, provides environmental guidance with which MPX must comply. MPX is in material compliance with all applicable environmental regulations and permit requirements.

MPX did not incur any material environmental expenditures in 2004 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007.

The Trinity Generating Facility has been designed to comply with Trinidad and Tobago environmental requirements. The facility operates in documented conformance with these applicable environmental regulations and permit requirements. Trinity Generating Facility is in material compliance with all applicable environmental regulations and permit requirements.

The Trinity Generating Facility did not incur any material environmental expenditures in 2004 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2007.

ITEM 3. LEGAL PROCEEDINGS

In June 1997, Jack J. Grynberg (Grynberg) filed suit under the Federal False Claims Act 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.

On June 4, 2004, following preliminary discovery, Williston Basin and Montana-Dakota joined with other defendants and filed a Motion to Dismiss on the grounds that the information upon which Grynberg based his complaint was publicly disclosed prior to the filing of his complaint and further, that he is not the original source of such information. The Motion to Dismiss is additionally based on the grounds that Grynberg disclosed the filing of the complaint prior to the entry of a court order allowing such disclosure and that Grynberg failed to provide adequate information to the government prior to filing suit.

In the event the Motion to Dismiss is not granted, it is expected that further discovery will follow. Williston Basin and Montana-Dakota believe Grynberg will not prevail in the suit or recover damages from Williston Basin and/or Montana-Dakota because insufficient facts exist to support the allegations. Williston Basin and Montana-Dakota believe Grynberg's claims are without merit and intend to vigorously contest this suit.

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.

Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a dozen 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 November 2004 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. Portions of 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, the National Environmental Policy Act, the Federal Land Management Policy Act, the National Historic Preservation Act and the Montana Environmental Policy Act. The cases involving alleged violations of the Federal Clean Water Act have been resolved without a finding that Fidelity is in violation of the Federal Clean Water Act. There presently are no claims pending for penalties, fines or damages under the Federal Clean Water Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural requirements and the lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity is unable to quantify the damages sought in any of these cases, and will be unable to do so until after completion of discovery in these separate cases. 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 Health Department in September 2003 that the North Dakota Health 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 North Dakota Health 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 in October 2003, in the Burleigh County District Court in Bismarck, North Dakota. Proceedings have been stayed pending discussions with the EPA, the North Dakota Health Department and the other electric generators.

In a related matter, the state of North Dakota and the EPA entered into a Memorandum of Understanding (MOU) on February 24, 2004, establishing the principles to be used by the state of North Dakota in completing dispersion modeling of air quality in Theodore Roosevelt National Park and other "Class I" areas in North Dakota and Montana. In April 2004, the Dakota Resource Council filed a petition for review of the MOU with the United States Eighth Circuit Court of Appeals. The petition was dismissed, without prejudice, in June 2004 upon stipulation of the EPA, the Dakota Resource Council and the state of North Dakota. The Company cannot predict the outcome of the North Dakota Health Department or Dakota Resource Council matters or their ultimate impact on its operations.

In December 2000, MBI 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. For additional information regarding this matter, see Items 1 and 2 – Business and Properties – Construction Materials and Mining – Environmental Matters.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

No matters were submitted to a vote of security holders during the fourth quarter of 2004.

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASE OF EQUITY SECURITIES

The Company's common stock is listed on the New York Stock Exchange and the Pacific Stock Exchange under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2004 and 2003 and dividends declared thereon were as follows:

	Common Stock Price (High)*	Common Stock Price (Low)*	Common Stock Dividends Per Share*
2004			
First Quarter	**$24.35**	**$22.67**	**$.17**
Second Quarter	**24.03**	**21.85**	**.17**
Third Quarter	**26.43**	**23.72**	**.18**
Fourth Quarter	**27.70**	**25.20**	**.18**
			$.70
2003			
First Quarter	$18.87	$16.41	$.16
Second Quarter	22.66	18.55	.16
Third Quarter	23.32	20.37	.17
Fourth Quarter	24.35	22.23	.17
			$.66

** Reflects the Company's three-for-two common stock split effected in October 2003.*

As of December 31, 2004, the Company's common stock was held by approximately 15,200 stockholders of record.

Operating Statistics	2004	2003	2002	2001	2000	1999
Selected Financial Data						
Operating revenues (000's):						
Electric	$ 178,803	$ 178,562	$ 162,616	$ 168,837	$ 161,621	$ 154,869
Natural gas distribution	316,120	274,608	186,569	255,389	233,051	157,692
Utility services	426,821	434,177	458,660	364,750	169,382	99,917
Pipeline and energy services	357,229	252,192	165,258	531,114	636,848	383,532
Natural gas and oil production	342,840	264,358	203,595	209,831	138,316	78,394
Construction materials and mining	1,322,161	1,104,408	962,312	806,899	631,396	469,905
Independent power production	43,059	32,261	2,998	–	–	–
Other	4,423	2,728	3,778	–	–	–
Intersegment eliminations	(272,199)	(191,105)	(114,249)	(113,188)	(96,943)	(64,500)
	$2,719,257	$2,352,189	$2,031,537	$2,223,632	$1,873,671	$1,279,809
Operating income (000's):						
Electric	$ 26,776	$ 35,761	$ 33,915	$ 38,731	$ 38,743	$ 35,727
Natural gas distribution	1,820	6,502	2,414	3,576	9,530	6,688
Utility services	(5,757)	12,885	13,980	25,199	16,606	11,518
Pipeline and energy services	24,690	35,155	39,091	30,368	28,782	40,627
Natural gas and oil production	178,897	118,347	85,555	103,943	66,510	26,845
Construction materials and mining	86,030	91,579	91,430	71,451	56,816	38,346
Independent power production	8,126	10,610	(1,176)	–	–	–
Other	136	1,233	908	–	–	–
	$ 320,718	$ 312,072	$ 266,117	$ 273,268	$ 216,987	$ 159,751
Earnings on common stock (000's):						
Electric	$ 12,790	$ 16,950	$ 15,780	$ 18,717	$ 17,733	$ 15,973
Natural gas distribution	2,182	3,869	3,587	677	4,741	3,192
Utility services	(5,650)	6,170	6,371	12,910	8,607	6,505
Pipeline and energy services	8,944	18,158	19,097	16,406	10,494	20,972
Natural gas and oil production	110,779	70,767*	53,192	63,178	38,574	16,207
Construction materials and mining	50,707	54,261*	48,702	43,199	30,113	20,459
Independent power production	26,309	11,415	307	–	–	–
Other	321	606	652	–	–	–
Earnings on common stock before cumulative effect of accounting change	206,382	182,196*	147,688	155,087	110,262	83,308
Cumulative effect of accounting change	–	(7,589)	–	–	–	–
	$ 206,382	$ 174,607	$ 147,688	$ 155,087	$ 110,262	$ 83,308
Earnings per common share before cumulative effect of accounting change – diluted	$ 1.76	$ 1.62*	$ 1.38	$ 1.52	$ 1.20	$ 1.01
Cumulative effect of accounting change	–	(.07)	–	–	–	–
	$ 1.76	$ 1.55	$ 1.38	$ 1.52	$ 1.20	$ 1.01
Pro forma amounts assuming retroactive application of accounting change:						
Net income (000's)	$ 207,067	$ 182,913	$ 146,052	$ 152,933	$ 108,951	$ 82,932
Earnings per common share – diluted	$ 1.76	$ 1.62	$ 1.36	$ 1.49	$ 1.17	$ 1.00
Common Stock Statistics						
Weighted average common shares outstanding – diluted (000's)	117,411	112,460	106,863	101,803	92,085	82,306
Dividends per common share	$ .7000	$ .6600	$ .6266	$ .6000	$ .5733	$ .5467
Book value per common share	$ 14.09	$ 12.66	$ 11.56	$ 10.60	$ 9.03	$ 7.83
Market price per common share (year end)	$ 26.68	$ 23.81	$ 17.21	$ 18.77	$ 21.67	$ 13.33
Market price ratios:						
Dividend payout	40%	43%	45%	39%	48%	54%
Yield	2.7%	2.9%	3.7%	3.3%	2.7%	4.2%
Price/earnings ratio	15.2x	15.4x	12.5x	12.3x	18.1x	13.2x
Market value as a percent of book value	189.4%	188.1%	148.8%	177.0%	239.9%	170.4%
Profitability Indicators						
Return on average common equity	13.2%	13.0%	12.5%	15.3%	14.3%	13.9%
Return on average invested capital	9.4%	8.9%	8.6%	10.1%	9.5%	9.6%
Interest coverage	7.1x	7.4x	7.7x	8.5x	8.3x	7.1x
Fixed charges coverage, including preferred dividends	4.7x	4.7x	4.8x	5.3x	4.1x	4.3x
General						
Total assets (000's)	$3,733,521	$3,380,592	$2,996,921	$2,675,978	$2,358,981	$1,806,648
Long-term debt, net of current maturities (000's)	$ 873,441	$ 939,450	$ 819,558	$ 783,709	$ 728,166	$ 563,545
Redeemable preferred stock (000's)	$ –	$ –	$ 1,300	$ 1,400	$ 1,500	$ 1,600
Capitalization ratios:						
Common equity	65%	60%	60%	58%	54%	54%
Preferred stocks	1	1	1	1	1	1
Long-term debt, net of current maturities	34	39	39	41	45	45
	100%	100%	100%	100%	100%	100%

** Before cumulative effect of the change in accounting for asset retirement obligations required by the adoption of SFAS No. 143, "Accounting for Asset Retirement Obligations," as discussed in Item 8 – Financial Statements and Supplementary Data – Notes 1 and 8.*

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

Operating Statistics	2004	2003	2002	2001	2000	1999
Electric						
Retail sales (thousand kWh)	**2,303,460**	2,359,888	2,275,024	2,177,886	2,161,280	2,075,446
Sales for resale (thousand kWh)	**821,516**	841,637	784,530	898,178	930,318	943,520
Electric system summer generating and firm purchase capability – kW (Interconnected system)	**544,220**	542,680	500,570	500,820	500,420	492,800
Demand peak – kW (Interconnected system)	**470,470**	470,470	458,800	453,000	432,300	420,550
Electricity produced (thousand kWh)	**2,552,873**	2,384,884	2,316,980	2,469,573	2,331,188	2,350,769
Electricity purchased (thousand kWh)	**794,829**	929,439	857,720	792,641	948,700	860,508
Average cost of fuel and purchased power per kWh	**$ .019**	$ .019	$ .018	$ .018	$ .016	$ .016
Natural Gas Distribution						
Sales (Mdk)	**36,607**	38,572	39,558	36,479	36,595	30,931
Transportation (Mdk)	**13,856**	13,903	13,721	14,338	14,314	11,551
Weighted average degree days – % of previous year's actual	**94%**	96%	109%	95%	113%	95%
Pipeline and Energy Services						
Transportation (Mdk)	**114,206**	90,239	99,890	97,199	86,787	78,061
Gathering (Mdk)	**80,527**	75,861	72,692	61,136	41,717	19,799
Natural Gas and Oil Production						
Production:						
Natural gas (MMcf)	**59,750**	54,727	48,239	40,591	29,222	24,652
Oil (000's of barrels)	**1,747**	1,856	1,968	2,042	1,882	1,758
Average realized prices:						
Natural gas (per Mcf)	**$ 4.69**	$ 3.90	$ 2.72	$ 3.78	$ 2.90	$ 1.94
Oil (per barrel)	**$34.16**	$27.25	$22.80	$24.59	$23.06	$15.34
Proved reserves:						
Natural gas (MMcf)	**453,200**	411,700	372,500	324,100	309,800	268,900
Oil (000's of barrels)	**17,100**	18,900	17,500	17,500	15,100	14,700
Construction Materials and Mining						
Construction materials (000's):						
Aggregates (tons sold)	**43,444**	38,438	35,078	27,565	18,315	13,981
Asphalt (tons sold)	**8,643**	7,275	7,272	6,228	3,310	2,993
Ready-mixed concrete (cubic yards sold)	**4,292**	3,484	2,902	2,542	1,696	1,186
Recoverable aggregate reserves (tons)	**1,257,498**	1,181,413	1,110,020	1,065,330	894,500	740,030
Coal (000's):						
Sales (tons)	**–***	–*	–*	1,171*	3,111	3,236
Lignite deposits (tons)	**11,400***	26,910*	37,761*	56,012*	145,643	182,761
Independent Power Production**						
Net generation capacity – kW	**279,600**	279,600	213,000	–	–	–
Electricity produced and sold (thousand kWh)	**204,425**	270,044	15,804	–	–	–

** Coal operations were sold effective April 30, 2001.*
*** Excludes equity method investments.*

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

This subsection of MD&A is an overview of the important factors that management focuses on in evaluating the Company's 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 MD&A 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 relation to any forward-looking statement.

Business and Strategy Overview

Prior to the fourth quarter of 2004, the Company reported 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. The independent power production and other operations did not individually meet the criteria to be considered a reportable segment. In the fourth quarter of 2004, the Company separated independent power production as a reportable business segment due to the significance of its operations. The Company's operations are now conducted through seven reportable segments and all prior period information has been restated to reflect this change.

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 investments in natural gas-fired electric generating facilities in Brazil and Trinidad and Tobago, as discussed in Item 8 – Financial Statements and Supplementary Data – Note 2.

The electric segment includes the electric generation, transmission and distribution operations of Montana-Dakota. The natural gas distribution segment includes the natural gas distribution operations of Montana-Dakota and Great Plains Natural Gas Co. The electric and natural gas distribution segments also supply related value-added products and services in the northern Great Plains. The utility services segment includes all the operations of Utility Services, Inc., which 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 includes WBI Holdings' 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 includes WBI Holdings' natural gas and oil acquisition, exploration, development and production operations, primarily in the Rocky Mountain region of the United States and in and around the Gulf of Mexico. The construction materials and mining segment includes the results of Knife River, which 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 operations of Centennial Resources owns, builds and operates electric generating facilities in the United States and has investments in electric generating facilities in Brazil, Trinidad and Tobago, and the United States. Electric capacity and energy produced at its power plants are sold primarily under mid- and long-term contracts to nonaffiliated entities.

Excluding the asset impairments at the pipeline and energy services segment of $5.3 million (after tax), 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, independent power production, and other are all from nonregulated operations.

The Company's strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share through internal growth along with acquisition of well-managed companies and development of projects that enhance shareholder value and are accretive to earnings per share and returns on invested capital.

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 2004 were $387 million and are estimated to be approximately $445 million for 2005.

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 experiences fluctuations in average natural gas and oil prices. 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.
- Economic volatility both domestically and in the foreign countries where the Company does business affects the Company's operations as well as the demand for its products and services and, as a result, may have a negative impact on the Company's future revenues.

- 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, more than a dozen 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.

For information pertinent to various commitments and contingencies, see Items 1 and 2 – Business and Properties, Item 3 – Legal Proceedings and Item 8 – Financial Statements and Supplementary Data – 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,	**2004**	2003	2002
	(Dollars in millions, where applicable)		
Electric	**$ 12.8**	$ 16.9	$ 15.8
Natural gas distribution	**2.2**	3.9	3.6
Utility services	**(5.6)**	6.2	6.4
Pipeline and energy services	**8.9**	18.2	19.1
Natural gas and oil production	**110.8**	63.0	53.2
Construction materials and mining	**50.7**	54.4	48.7
Independent power production	**26.3**	11.4	.3
Other	**.3**	.6	.6
Earnings on common stock	**$206.4**	$174.6	$147.7
Earnings per common share – basic	**$ 1.77**	$ 1.57	$ 1.39
Earnings per common share – diluted	**$ 1.76**	$ 1.55	$ 1.38
Return on average common equity	**13.2%**	13.0%	12.5%

2004 compared to 2003 Consolidated earnings for 2004 increased $31.8 million from the comparable prior period. The earnings increase was largely the result of:

- Higher natural gas prices of 20 percent and higher oil prices of 25 percent at the natural gas and oil production business
- Increased natural gas production of 9 percent at the natural gas and oil production business
- Higher net income of $14.8 million from the Company's share of its equity method investment in Brazil
- Favorable resolution of federal and related state income tax matters of $8.3 million, including interest
- The absence in 2004 of a noncash transition charge in 2003 of $7.6 million (after tax), reflecting the cumulative effect of an accounting change, as discussed in Item 8 – Financial Statements and Supplementary Data – Notes 1 and 8

Partially offsetting the increase were:

- Higher operation and maintenance expense including payroll, severance-related expenses, pension costs, higher fuel costs of which a significant portion was not recovered through higher prices at the construction materials and mining business, as well as costs associated with adverse weather at the Texas construction materials and mining business
- Lower inside electrical margins at the utility services business, including the effect of losses on a few large jobs of $5.8 million (after tax)
- A $4.0 million (before and after tax) noncash goodwill impairment relating to the Company's cable and pipeline magnetization and location business, as well as a $1.3 million (after tax) adjustment reflecting the reduction in value of certain gathering facilities in the Gulf Coast region

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 business 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 method investment in Brazil
- Increased earnings at the natural gas and oil production business 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, as discussed in Item 8 – Financial Statements and Supplementary Data – Note 18, and the $12.7 million ($7.7 million after tax) noncash transition charge in 2003, reflecting the cumulative effect of an accounting change, as previously discussed, and higher depreciation, depletion and amortization expense
- Higher earnings 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
- Increased earnings at the natural gas distribution business 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

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 were a reflection of the continuing effects of the soft economy and the downturn in the telecommunications market.

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,	2004	2003	2002
	(Dollars in millions, where applicable)		
Operating revenues	**$178.8**	$178.6	$162.6
Operating expenses:			
Fuel and purchased power	**64.6**	62.0	56.0
Operation and maintenance	**59.0**	52.9	46.0
Depreciation, depletion and amortization	**20.2**	20.2	19.6
Taxes, other than income	**8.2**	7.7	7.1
	152.0	142.8	128.7
Operating income	**$ 26.8**	$ 35.8	$ 33.9
Retail sales (million kWh)	**2,303.5**	2,359.9	2,275.0
Sales for resale (million kWh)	**821.5**	841.6	784.6
Average cost of fuel and purchased power per kWh	**$ .019**	$ .019	$ .018

2004 compared to 2003 Electric earnings decreased $4.1 million (25 percent) compared to the prior year, largely as a result of the following:

- An increase in operation and maintenance expense of $3.7 million (after tax) due primarily to increased payroll, severance-related and pension expenses
- Lower retail sales margins largely the result of decreased retail sales volumes of 2.4 percent, primarily the result of lower residential sales volumes due to cooler summer weather

Partially offsetting the decrease in earnings was a favorable resolution of federal and related state income tax matters of $1.7 million (after tax), including interest.

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

Partially offsetting the earnings increase were:

- 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

Natural Gas Distribution

Years ended December 31,	2004	2003	2002
	(Dollars in millions, where applicable)		
Operating revenues:			
Sales	**$311.5**	$270.2	$182.5
Transportation and other	**4.6**	4.4	4.1
	316.1	274.6	186.6
Operating expenses:			
Purchased natural gas sold	**251.1**	211.1	132.9
Operation and maintenance	**48.3**	41.8	36.5
Depreciation, depletion and amortization	**9.4**	10.0	9.9
Taxes, other than income	**5.5**	5.2	4.9
	314.3	268.1	184.2
Operating income	**$ 1.8**	$ 6.5	$ 2.4
Volumes (MMdk):			
Sales	**36.6**	38.6	39.6
Transportation	**13.9**	13.9	13.7
Total throughput	**50.5**	52.5	53.3
Degree days (% of normal)*	**90.7%**	97.3%	101.1%
Average cost of natural gas, including transportation thereon, per dk	**$ 6.86**	$ 5.47	$ 3.22

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

2004 compared to 2003 The natural gas distribution business experienced a decrease in earnings of $1.7 million (44 percent) compared to the prior year. The earnings decrease largely resulted from:

- Higher payroll, severance-related expenses, pension and other operational expenses of $5.2 million (after tax)
- Decreased retail sales volumes of 5.1 percent, primarily lower residential and commercial sales volumes as a result of 6 percent warmer weather compared to last year

Partially offsetting the decrease in earnings were:

- A favorable resolution of federal and related state income tax matters of $3.0 million (after tax), including interest
- Higher retail sales prices, the result of rate increases effective in South Dakota, North Dakota and Minnesota

The pass-through of higher natural gas prices is reflected in the increase in both sales revenues and purchased natural gas sold.

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
- 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
- Higher income taxes in 2003
- Decreased returns on natural gas held in storage
- Lower retail sales volumes due to weather that was 4 percent warmer than the comparable prior period

The pass-through of higher natural gas prices is reflected in the increase in both sales revenues and purchased natural gas sold.

Utility Services

Years ended December 31,	**2004**	2003	2002
		(Dollars in millions)	
Operating revenues	**$426.8**	$434.2	$458.7
Operating expenses:			
Operation and maintenance	**405.6**	395.9	419.0
Depreciation, depletion and amortization	**11.1**	10.3	9.9
Taxes, other than income	**15.8**	15.1	15.8
	432.5	421.3	444.7
Operating income (loss)	**$ (5.7)**	$ 12.9	$ 14.0

2004 compared to 2003 Utility services experienced a $5.6 million loss compared to $6.2 million in earnings for the prior year. The earnings decrease was attributable to:

- Decreased inside electrical margins, including the effect of losses on a few large jobs of $5.8 million (after tax)
- Increased severance and other general and administrative expenses of $3.6 million (after tax), including higher consulting and legal fees as well as other outside service costs

The decrease in earnings was partially offset by increased line construction margins.

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
- Lower workloads and margins in the telecommunications industry in the Rocky Mountain region
- Increased selling, general and administrative expenses
- Lower inside electrical workloads and margins in the Central region

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)
- Higher line construction margins in the Northwest and Rocky Mountain regions

Lower margins were a reflection of the continuing effects of the soft economy in this sector and the downturn in the telecommunications market.

Pipeline and Energy Services

Years ended December 31,	2004	2003	2002
		(Dollars in millions)	
Operating revenues:			
Pipeline	**$ 87.2**	$ 97.2	$ 95.3
Energy services	**270.0**	155.0	69.9
	357.2	252.2	165.2
Operating expenses:			
Purchased natural gas sold	**249.8**	149.5	58.3
Operation and maintenance	**51.1**	46.6	47.3
Depreciation, depletion and amortization	**17.8**	15.0	14.8
Taxes, other than income	**7.7**	5.9	5.7
Asset impairments	**6.1**	–	–
	332.5	217.0	126.1
Operating income	**$ 24.7**	$ 35.2	$ 39.1
Transportation volumes (MMdk):			
Montana-Dakota	**32.5**	34.1	33.3
Other	**81.7**	56.1	66.6
	114.2	90.2	99.9
Gathering volumes (MMdk)	**80.5**	75.9	72.7

2004 compared to 2003 Earnings at the pipeline and energy services business decreased $9.3 million (51 percent) due largely to:

- A $4.0 million (before and after tax) noncash goodwill impairment and a $1.3 million (after tax) asset valuation adjustment, as previously discussed
- Increased operating costs of $5.3 million (after tax) including costs associated with last year's expansion of pipeline and gathering operations, as well as higher payroll-related costs
- Higher financing-related costs of $2.2 million (after tax)
- Lower average rates of $1.5 million (after tax), due in part to the estimated effects of a FERC rate order received in July 2003 and rehearing order received in May 2004 which resulted in lower rates effective July 1, 2004

Partially offsetting the decrease in earnings were:

- Increased natural gas transportation volumes of $3.5 million (after tax), including:
  - Higher volumes transported on the Grasslands Pipeline (which began providing natural gas transmission service late in 2003)
  - Higher natural gas volumes transported into storage which were largely commodity price related
- A favorable resolution of federal and related state income tax matters of $1.6 million (after tax), including interest

The increase in energy services revenues and the related increase in purchased natural gas sold includes the effect of higher natural gas prices and volumes since the comparable prior period.

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
- 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.

Natural Gas and Oil Production

Years ended December 31,	2004	2003	2002
	(Dollars in millions, where applicable)		
Operating revenues:			
Natural gas	$280.4	$213.5	$131.0
Oil	59.7	50.6	42.1
Other	2.8	.2	30.5*
	342.9	264.3	203.6
Operating expenses:			
Purchased natural gas sold	2.7	.1	.1
Operation and maintenance:			
Lease operating costs	33.0	31.6	27.5
Gathering and transportation	11.6	14.7	12.3
Other	23.1	17.2	15.8
Depreciation, depletion and amortization	70.8	61.0	48.7
Taxes, other than income:			
Production and property taxes	22.6	21.0	12.7
Other	.2	.4	.9
	164.0	146.0	118.0
Operating income	$178.9	$118.3	$ 85.6
Production:			
Natural gas (MMcf)	59,750	54,727	48,239
Oil (000's of barrels)	1,747	1,856	1,968
Average realized prices (including hedges):			
Natural gas (per Mcf)	$ 4.69	$ 3.90	$ 2.72
Oil (per barrel)	$34.16	$27.25	$22.80
Average realized prices (excluding hedges):			
Natural gas (per Mcf)	$ 4.90	$ 4.28	$ 2.54
Oil (per barrel)	$37.75	$28.42	$23.26
Production costs, including taxes, per net equivalent Mcf:			
Lease operating costs	$ .47	$ .48	$ .46
Gathering and transportation	.17	.22	.20
Production and property taxes	.32	.32	.21
	$ .96	$ 1.02	$ .87

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

2004 compared to 2003 Natural gas and oil production earnings increased $47.8 million (76 percent) due to:

- Higher average realized natural gas prices of 20 percent due in part to the Company's ability to access higher and more stable-priced markets for much of its operated natural gas production through the recently constructed Grasslands Pipeline
- Higher natural gas production of 9 percent, largely the result of drilling activity
- The absence in 2004 of a $12.7 million ($7.7 million after tax) noncash transition charge in 2003, reflecting the cumulative effect of an accounting change, as previously discussed
- Higher average realized oil prices of 25 percent

Partially offsetting the increase in earnings were:

- Higher depreciation, depletion and amortization expense of $6.0 million (after tax) due to higher rates and higher natural gas production volumes
- Higher general and administrative costs of $3.5 million (after tax) due primarily to increased payroll-related expenses and outside services

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
- 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
- Increased depreciation, depletion and amortization expense due to higher natural gas production volumes and higher rates
- Higher lease operating expenses due in part to increased natural gas production
- Higher general and administrative costs
- Decreased oil production of 6 percent
- Higher interest expense

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."

Construction Materials and Mining

Years ended December 31,	2004	2003	2002
		(Dollars in millions)	
Operating revenues	**$1,322.2**	$1,104.4	$962.3
Operating expenses:			
Operation and maintenance	**1,132.3**	924.2	797.7
Depreciation, depletion and amortization	**69.6**	63.6	54.4
Taxes, other than income	**34.3**	25.0	18.8
	1,236.2	1,012.8	870.9
Operating income	**$ 86.0**	$ 91.6	$ 91.4
Sales (000's):			
Aggregates (tons)	**43,444**	38,438	35,078
Asphalt (tons)	**8,643**	7,275	7,272
Ready-mixed concrete (cubic yards)	**4,292**	3,484	2,902

2004 compared to 2003 Construction materials and mining earnings decreased $3.7 million (7 percent) due to:

- Lower aggregate and construction margins of $10.5 million (after tax) from existing operations largely as a result of:
  - The absence of certain large projects reflected in 2003 results
  - Wet weather which severely impacted operations in Texas
  - Increased fuel costs of which a significant portion was not recovered through higher prices
- Higher general and administrative expenses of $5.3 million (after tax), including payroll-related costs, insurance and professional services

Partially offsetting the decrease in earnings were:

- Increased ready-mixed concrete margins of $2.7 million (after tax), largely as a result of higher sales volumes from existing operations
- Earnings from companies acquired since the comparable prior period contributed approximately 5 percent of earnings

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 prior period

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

Independent Power Production

Years ended December 31,	2004	2003	2002
		(Dollars in millions)	
Operating revenues	**$43.1**	$32.3	$ 3.0
Operating expenses:			
Operation and maintenance	**23.0**	13.8	3.7
Depreciation, depletion and amortization	**9.6**	7.9	.4
Taxes, other than income	**2.4**	–	–
	35.0	21.7	4.1
Operating income (loss)	**$ 8.1**	$10.6	$(1.1)
Net generation capacity – kW*	**279,600**	279,600	213,000
Electricity produced and sold (thousand kWh)*	**204,425**	270,044	15,804

**Excludes equity method investments.*
NOTE: The earnings from the Company's equity method investments are not reflected in the above table.

2004 compared to 2003 Earnings for the independent power production business were $26.3 million compared to $11.4 million in 2003. This increase is largely due to:

- Higher net income of $14.8 million from the Company's share of its equity method investment in Brazil due primarily to:
  - Changes in value of the embedded derivative in the Brazilian electric power sales contract, net of lower operating margins resulting from the contract annual revenue reset provision, as well as other foreign currency changes, totaling $8.5 million (after tax)
  - Lower financing costs of $4.8 million (after tax), largely the result of obtaining low-cost, long-term financing for the operation in mid-2003
- Earnings from acquisitions and equity method investments acquired since the comparable prior period contributed approximately 7 percent of earnings

For additional information regarding equity method investments, see Item 8 – Financial Statements and Supplementary Data – Note 2.

2003 compared to 2002 Earnings for the independent power production business 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
- Higher net income of $3.7 million from the Company's share of its equity method 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)
  - Foreign currency gains from an increase in value of the Brazilian Real

  Partially offset by:

  - The mark-to-market loss on an embedded derivative in the electric power sales contract
  - Higher interest expense due to a full year of debt in 2003

Other and Intersegment Transactions

Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's other operations and the elimination of intersegment transactions. The amounts relating to these items are as follows:

Years ended December 31,	2004	2003	2002
		(In millions)	
Other:			
Operating revenues	$ 4.4	$ 2.7	$ 3.8
Operation and maintenance	4.0	1.2	2.7
Depreciation, depletion and amortization	.3	.3	.3
Intersegment transactions:			
Operating revenues	$272.2	$191.1	$114.3
Purchased natural gas sold	253.7	176.5	98.8
Operation and maintenance	18.5	14.6	15.5

For further information on intersegment eliminations, see Item 8 – Financial Statements and Supplementary Data – Note 13.

RISK FACTORS AND CAUTIONARY STATEMENTS THAT MAY AFFECT FUTURE RESULTS

The Company is including the following factors and cautionary statements in this Form 10-K 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 and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, which cannot be predicted or controlled.

These factors include: price fluctuations in natural gas and crude oil prices; fluctuations in commodity price basis differentials; availability of economic supplies of natural gas; drilling successes in natural gas and oil operations; the timely receipt of necessary permits and approvals; 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. Significant changes in these factors could negatively affect the results of operations and financial condition of the Company's natural gas and oil production and pipeline and energy services businesses.

The construction and operation of power generation facilities may involve unanticipated changes or delays that could negatively impact the Company's business and its results of operations.

The construction and 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. Such unanticipated events could negatively impact the Company's business and its results of operations.

The Company's utility services business operates in highly competitive markets characterized by low margins in a number of service lines and geographic areas.

This business' ability to return to profitability on a sustained basis will depend upon improved capital spending for electric construction services and management's ability to successfully refocus the business on more profitable markets, reduce operating costs and implement process improvements in project management.

Economic volatility affects the Company's operations as well as the demand for its products and services and, as a result, may have a negative impact on the Company's future revenues.

The global demand for natural resources, interest rates, governmental budget constraints, and the ongoing threat of terrorism can create volatility in the financial markets. 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.

The Company relies on financing sources and capital markets. If the Company is unable to obtain 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 its 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 costs of operations, impact or limit 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, and delays 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, a number of 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 delay and/or 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 Foreign Operations

The value of the Company's investments 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 an electric power sales contract 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.

Negotiations with Petrobras may impact the Company's future earnings.

The Company's future earnings from its investment in Brazilian power operations may be affected by the outcome of negotiations between its 49 percent-owned investee, MPX, and Petrobras over continuing payments by Petrobras under an electric power sales contract covering capacity and energy associated with the Termoceara Generating Facility.

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 production 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. The increase in competition could negatively affect the Company's results of operations and financial condition.

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 and construction and drilling activities for the pipeline and energy services and natural gas and oil production businesses. In addition, severe weather can be destructive, causing outages, reduced natural gas and oil production, 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.* 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 2005, diluted, are projected in the range of $1.70 to $1.90.
- The Company expects the percentage of 2005 earnings per common share, diluted, by quarter to be in the following approximate ranges:
  - First quarter – 10 percent to 15 percent
  - Second quarter – 20 percent to 25 percent
  - Third quarter – 37 percent to 42 percent
  - Fourth quarter – 23 percent to 28 percent
- These projections do not take into consideration any potential effect from recent events related to the Brazilian electric power sales contract. Excluding any such effects, earnings estimated for 2005 from existing Brazilian operations are in the range of 4 percent to 6 percent of consolidated earnings for the Company. For further information regarding this matter, see Item 8 – Financial Statements and Supplementary Data – Note 2.
- 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 anticipates investing approximately $445 million in capital expenditures during 2005.
- 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.

Electric

- The expected earnings in 2005 are anticipated to be slightly lower than 2004 earnings because of anticipated higher operation and maintenance expenses primarily related to higher benefit costs, and the absence of the favorable resolution of income tax matters.
- As part of the North Dakota Industrial Commission's Lignite Vision 21 project, the Company submitted an air quality permit application in May 2004 to construct a 175-megawatt coal-fired plant at Gascoyne, N.D. The air permit application is now under review at the North Dakota Health Department. This segment also is involved in the review of other potential projects to replace capacity associated with expiring purchased power contracts and to provide for future growth. The costs of building and/or acquiring the additional generating capacity needed by the utility are expected to be recovered in rates.
- 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.

Natural gas distribution

- The expected earnings for this segment for 2005 are projected to be somewhat higher than the earnings for 2004 primarily the result of rate relief and the assumed return to normal weather, which for 2004 was 9 percent warmer than normal.
- In September 2004, a natural gas rate case was filed with the MPUC requesting an increase of $1.4 million annually, or 4.0 percent. The Company requested an interim increase of $1.4 million annually and in November 2004, the MPUC issued an Order approving the requested interim increase effective January 10, 2005, subject to refund. A final order is expected in late 2005.
- 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.

Utility services

- Revenues are expected to be in the range of $440 million to $490 million in 2005.
- The Company anticipates margins to increase substantially in 2005 as compared to 2004 levels.
- Work backlog as of December 31, 2004, was approximately $238 million, compared to $148 million at December 31, 2003.

Pipeline and energy services

- In 2005, total natural gas gathering and transportation throughput is expected to increase approximately 5 percent to 10 percent over 2004 levels.
- 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 and storage rate reductions due to the estimated effects of a FERC rate order received in July 2003 and rehearing order received in May 2004 have been reflected in the Company's 2005 earnings projections.

Natural gas and oil production

- The Company is expecting to drill up to 500 wells in 2005, dependent on the timely receipt of regulatory approvals. Delays in receipt of drilling permits are affecting producers throughout the Rocky Mountain region.
- In 2005, the Company expects a combined natural gas and oil production increase of approximately 6 percent to 8 percent over 2004 levels. A portion of this increase is predicated on the timely receipt of various regulatory approvals. Currently, this segment's net combined natural gas and oil production is approximately 185,000 Mcf equivalent to 195,000 Mcf equivalent per day.
- Estimates of natural gas prices in the Rocky Mountain region for February through December 2005 reflected in the Company's 2005 earnings guidance are in the range of $4.25 to $4.75 per Mcf. The Company's estimates for natural gas prices on the NYMEX for February through December 2005, reflected in the Company's 2005 earnings guidance, are in the range of $5.00 to $5.50 per Mcf. During 2004, more than three-fourths of this segment's natural gas production was priced using Rocky Mountain or other non-NYMEX prices.
- Estimates of NYMEX crude oil prices for February through December 2005, reflected in the Company's 2005 earnings guidance, are projected in the range of $35 to $40 per barrel.
- The Company has hedged a portion of its 2005 estimated natural gas production. The Company has entered into agreements representing approximately 35 percent to 40 percent of its 2005 estimated annual natural gas production. The agreements are at various indices/prices and range from a low Ventura index of $4.75 to a high NYMEX price of $10.18 per Mcf. Ventura is an index pricing point related to Northern Natural Gas Co.'s system.
- This segment has hedged a portion of its 2005 oil production. The Company has entered into agreements at NYMEX prices with a low of $30.70 and a high of $52.05 representing approximately 45 percent to 50 percent of its 2005 estimated annual oil production.
- For 2005, the Company may hedge up to 70 percent of its existing natural gas and oil production that qualifies for hedge accounting, based on established pricing criteria.

Construction materials and mining

- The Company anticipates improved earnings in 2005 with an expected return to more normal weather conditions in Texas.
- Aggregate, ready-mixed concrete and asphalt volumes in 2005 are expected to be comparable to 2004 levels.
- Revenues in 2005 are expected to be comparable to 2004 levels.
- The Company expects that the replacement funding legislation for the TEA-21 will be equal to or higher than previous funding levels.
- Work backlog as of December 31, 2004, was approximately $426 million, compared to $332 million at December 31, 2003.

Independent power production

- Earnings projections for 2005 are expected to be slightly lower than 2004 earnings primarily due to benefits realized in 2004 from foreign currency gains and the effects of the embedded derivative in the Brazilian electric power sales contract.
- Earnings projections do not take into consideration any potential effect from recent events related to the Brazilian electric power sales contract.
- The Company anticipates making an additional investment in an international project in 2005 which is reflected in earnings projections.
- The Company is constructing a 116-megawatt coal-fired electric generating facility near Hardin, Montana. A power sales agreement with Powerex Corp., a subsidiary of BC Hydro, has been secured for the entire output of the plant for a term expiring October 31, 2008, with the purchaser having an option for a two-year extension. The projected on-line date for this plant is late 2005.

NEW ACCOUNTING STANDARDS

FIN 46 (revised)

In December 2003, the Financial Accounting Standards Board (FASB) issued FASB Interpretation No. 46 (revised December 2003), "Consolidation of Variable Interest Entities" (FIN 46 (revised)), which replaced 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. The adoption of FIN 46 (revised) did not have an effect on the Company's financial position or results of operations.

FSP Nos. FAS 106-1 and FAS 106-2

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" (FSP No. FAS 106-1). FSP 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).

In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003" (FSP No. FAS 106-2).

The Company elected the one-time deferral of accounting for the effects of the 2003 Medicare Act in the quarter ended March 31, 2004, the first period in which the plan's accounting for the effects of the 2003 Medicare Act normally would have been reflected in the Company's financial statements.

During the second quarter of 2004, the Company adopted FSP No. FAS 106-2 retroactive to the beginning of the year. The Company expects to be entitled to a federal subsidy. The expected federal subsidy reduced the accumulated postretirement benefit obligation (APBO) at January 1, 2004, by approximately $3.2 million, and net periodic benefit cost for 2004 by approximately $285,000 (as compared with the amount calculated without considering the effects of the subsidy). In addition, the Company expects a reduction in future participation in the postretirement plans, which further reduced the APBO at January 1, 2004, by approximately $12.7 million and net periodic benefit cost for 2004 by approximately $1.3 million.

FSP Nos. FAS 141-1 and FAS 142-1

In April 2004, the FASB issued FASB Staff Position Nos. FAS 141-1 and FAS 142-1, "Interaction of FASB Statements No. 141, 'Business Combinations,' and No. 142, 'Goodwill and Other Intangible Assets,' and EITF Issue No. 04-2, 'Whether Mineral Rights are Tangible or Intangible Assets,'" (FSP Nos. FAS 141-1 and FAS 142-1). The Company adopted FSP Nos. FAS 141-1 and FAS 142-1 in the second quarter of 2004. FSP Nos. FAS 141-1 and FAS 142-1 required reclassification of the Company's leasehold rights at its construction materials and mining operations from other intangible assets, net, to property, plant and equipment, as well as changes to Notes to Consolidated Financial Statements. FSP Nos. FAS 141-1 and FAS 142-1 affected the asset classification in the consolidated balance sheet and associated footnote disclosure only, so the reclassifications did not affect the Company's stockholders' equity, cash flows or results of operations.

FSP No. FAS 142-2

In September 2004, the FASB Staff issued FASB Staff Position No. FAS 142-2, "Application of FASB Statement No. 142, Goodwill and Other Intangible Assets, to Oil- and Gas-Producing Entities," (FSP No. FAS 142-2). FSP No. FAS 142-2 indicates that the exception in SFAS No. 142, "Goodwill and Other Intangible Assets," does not change the accounting prescribed in SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies," including the balance sheet classification of drilling and mineral rights of oil and gas producing entities and, as a result, the contractual mineral rights should continue to be classified as part of property, plant and equipment. FSP No. FAS 142-2 did not have an effect on the Company's financial position, results of operations or cash flows.

SAB No. 106

In September 2004, the SEC issued Staff Accounting Bulletin No. 106 (SAB No. 106) which is an interpretation regarding the application of SFAS No. 143 by oil and gas producing companies following the full-cost accounting method. SAB No. 106 shall be applied to all entities subject to SAB No. 106 as of the beginning of the first quarter after October 4, 2004. The adoption of SAB No. 106 is not expected to have a material effect on the Company's financial position or results of operations.

SFAS No. 123 (revised)

In December 2004, the FASB issued SFAS No. 123 (revised 2004), "Share-Based Payment" (SFAS No. 123 (revised)). SFAS No. 123 (revised) revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. SFAS No. 123 (revised) requires a company to record compensation expense for all awards granted after the date of adoption of SFAS No. 123 (revised) and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. SFAS No. 123 (revised) is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company is evaluating the effects of the adoption of SFAS No. 123 (revised).

For further information on FIN 46 (revised), FSP Nos. FAS 106-1 and FAS 106-2, FSP Nos. FAS 141-1 and FAS 142-1, FSP No. FAS 142-2, SAB No. 106, and SFAS No. 123 (revised), see Item 8 – Financial Statements and Supplementary Data – Note 1.

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 Item 8 – Financial Statements and Supplementary Data – Note 1.

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 an electric power sales contract related to an equity method investment in Brazil, as discussed in Item 8 – Financial Statements and Supplementary Data – Note 2. 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. 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 when the estimates are made.

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 SEC, and the cost 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 liability assumptions and may from time to time change its liability 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. In as much as contract prices are generally set before the work is performed, the estimates pertaining to 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 when 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 leasehold rights).

The fair value of owned recoverable aggregate reserve deposits is 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.

The fair value of leasehold rights 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 considerable degree 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.

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 when 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 2004 increased $14.7 million from the comparable 2003 period, the result of an increase in net income of $31.7 million and higher depreciation, depletion and amortization expense of $20.4 million largely due to higher rates and higher natural gas production volumes at the natural gas and oil production business and higher property, plant and equipment due to acquisitions at the construction materials and mining business. Also contributing to the increase were changes in working capital of $19.1 million and asset impairments of $6.1 million. Partially offsetting the increase in cash flows from operating activities were decreased deferred income taxes of $31.4 million, which reflects the effects of higher depreciation, depletion and amortization expense, as previously discussed, as well as lower tax depreciation in 2004 on the Grasslands Pipeline. Also offsetting the increase were increased earnings, net of distributions, from equity method investments of $18.2 million and the absence in 2004 of the 2003 cumulative effect of an accounting change of $7.6 million.

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.

Investing activities Cash flows used in investing activities in 2004 decreased $34.4 million compared to the comparable 2003 period, the result of a decrease in net capital expenditures (capital expenditures; acquisitions, net of cash acquired; and net proceeds from the sale or disposition of property) of $77.0 million and an increase in proceeds from notes receivable of $14.2 million, offset in part by an increase in investments of $56.8 million, including equity method investments. Net capital expenditures exclude the noncash transactions related to acquisitions, including the issuance of the Company's equity securities. The noncash transactions were $33.1 million and $42.4 million for 2004 and 2003, respectively.

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.

Financing activities Cash flows provided by financing activities in 2004 decreased $54.8 million compared to the comparable 2003 period, primarily the result of a decrease in proceeds from the issuance of long-term debt of $204.4 million. A decrease in repayment of long-term debt of $67.7 million and an increase in proceeds from the issuance of common stock of $69.6 million, primarily due to net proceeds received from an underwritten public offering, partially offset the decrease in cash provided by 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.

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, 2004, certain Pension Plans' accumulated benefit obligations exceeded these plans' assets by approximately $3.7 million. Pretax pension expense (income) reflected in the years ended December 31, 2004, 2003 and 2002, was $4.1 million, $153,000, and ($2.4) million, respectively. The Company's pension expense is currently projected to be approximately $7.0 million to $8.0 million in 2005. 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 2004, 2003 and 2002 were approximately $1.2 million, $1.6 million, and $1.2 million, respectively. For further information on the Company's Pension Plans, see Item 8 – Financial Statements and Supplementary Data – Note 15.

Capital expenditures

The Company's capital expenditures for 2002 through 2004 and as anticipated for 2005 through 2007 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2002	2003	2004	2005	2006	2007
			(In millions)			
Capital expenditures:						
Electric	$ 27.8	$ 28.5	**$ 18.8**	$ 24.8	$ 63.5	$167.2
Natural gas distribution	11.0	15.7	**17.4**	15.2	15.8	13.4
Utility services	17.3	7.8	**8.5**	12.8	11.8	12.4
Pipeline and energy services	21.5	93.0	**38.3**	35.4	29.9	34.6
Natural gas and oil production	136.4	101.7	**111.5**	157.2	146.7	149.2
Construction materials and mining	106.9	128.5	**133.0**	101.3	93.2	73.4
Independent power production	89.6	110.9	**76.2**	86.5	38.3	20.7
Other	6.1	1.9	**4.2**	13.0	.3	.2
	416.6	488.0	**407.9**	446.2	399.5	471.1
Net proceeds from sale or disposition of property	(16.2)	(14.4)	**(20.5)**	(1.8)	(2.8)	(1.7)
Net capital expenditures	400.4	473.6	**387.4**	444.4	396.7	469.4
Retirement of long-term debt	82.6	105.7	**38.0**	72.0	138.8	132.9
	$483.0	$579.3	**$425.4**	$516.4	$535.5	$602.3

**The estimated 2005 through 2007 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 2004, 2003 and 2002, related to acquisitions, in the preceding table include the following noncash transactions: issuance of the Company's equity securities of $33.1 million in 2004, $42.4 million in 2003 and $47.2 million in 2002.

In 2004, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Idaho, Iowa and Minnesota and an independent power production operating and development company in Colorado. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired prior to 2004, consisting of the Company's common stock and cash, was $70.3 million.

The 2004 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 2005 through 2007 include those for:

- Potential future acquisitions
- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering expansion projects
- Further enhancement of natural gas and oil production and reserve growth
- Power generation opportunities, including certain construction costs for an additional 175 megawatts of capacity and for a 116-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 2005 through 2007 will be met from various sources. These sources include internally generated funds; commercial paper credit facilities at Centennial 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, 2004.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling $90 million at December 31, 2004. There were no amounts outstanding under the credit agreement at December 31, 2004. The credit agreement supports the Company's $75 million commercial paper program. Under the Company's commercial paper program, $37.0 million was outstanding at December 31, 2004. 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.

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 $56,000 (after tax) based on December 31, 2004, variable rate borrowings.

Prior to the maturity of the credit agreement, the Company plans to negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event the Company is 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, 2004. 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 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 have been 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 fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Indenture and, in some cases, to certify to the trustee 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 tests, as of December 31, 2004, the Company could have issued approximately $343 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 4.7 times for the twelve months ended December 31, 2004 and 2003. Additionally, the Company's first mortgage bond interest coverage was 7.1 times and 7.4 times for the twelve months ended December 31, 2004 and 2003, respectively. Common stockholders' equity as a percent of total capitalization (net of long-term debt due within one year) was 65 percent and 60 percent at December 31, 2004 and 2003, respectively.

Centennial Energy Holdings, Inc. Centennial has three revolving credit agreements with various banks and institutions that support $335 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2004. Under the Centennial commercial paper program, $26.0 million was outstanding at December 31, 2004. 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. One of these credit agreements is for $300 million and expires on August 17, 2007, and another agreement is for $25 million and expires on April 30, 2007. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities. The third agreement is an uncommitted line for $10 million, which was effective on January 25, 2005, and may be terminated by the bank at any time.

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, 2004. The ability to request additional borrowings under this master shelf agreement expires on February 28, 2005. The Company is in discussion regarding potential renewal of this facility. 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 $39,000 (after tax) based on December 31, 2004, variable rate borrowings. Based on Centennial's overall interest rate exposure at December 31, 2004, 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, which 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, 2004. 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 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, 2004. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2005.

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, 2004. 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 in connection with the Company's equity method investment in the Termoceara Generating Facility, as discussed in Item 8 – Financial Statements and Supplementary Data – 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, 2004, the aggregate amount of borrowings outstanding subject to these guarantees was $34.9 million and the scheduled repayment of these borrowings is $11.0 million in 2005, $10.7 million in 2006 and 2007 and $2.5 million in 2008. The individual investor (who through EBX Empreendimentos Ltda. (EBX), a Brazilian company, owns 51 percent of MPX) has also guaranteed these loans. In the event MPX defaults under its obligation, Centennial and the individual investor would be required to make payments under their guarantees, which are joint and several obligations. 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, 2004, Centennial was contingently liable for performance of certain of its subsidiaries under approximately $375 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 is 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 Item 8 – Financial Statements and Supplementary Data – Notes 7 and 18. At December 31, 2004, the Company's commitments under these obligations were as follows:

	2005	2006	2007	2008	2009	Thereafter	Total
				(In millions)			
Long-term debt	$ 72.0	$138.8	$132.9	$161.3	$ 86.9	$353.6	$ 945.5
Estimated interest payments*	53.7	49.5	38.7	32.5	25.3	126.2	325.9
Operating leases	14.7	10.5	6.6	5.1	3.5	25.2	65.6
Purchase commitments	223.6	105.7	65.4	50.5	46.9	236.4	728.5
	$364.0	$304.5	$243.6	$249.4	$162.6	$741.4	$2,065.5

** Estimated interest payments are calculated based on the applicable rates and payment dates.*

In addition to the above obligations, the Company has certain purchase obligations for natural gas connected to its gathering system. These purchases and the resale of the natural gas are at market-based prices. These obligations continue as long as natural gas is produced. However, if the purchase and resale of natural gas becomes uneconomical, the purchase commitments can be canceled by the Company with 60 days notice. These purchase obligations are currently estimated at approximately $10 million annually.

EFFECTS OF INFLATION

Inflation did not have a significant effect on the Company's operations in 2004, 2003 or 2002.

ITEM 7A. 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 that natural gas and oil price derivative instruments and interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. 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; if the derivative instrument expires or is sold, terminated or exercised; 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

Fidelity 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 its 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.

The following table summarizes hedge agreements entered into by Fidelity as of December 31, 2004. These agreements call for Fidelity 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 2005	$5.39	8,020	$(4,187)
	Weighted Average Floor/Ceiling (Per MMBtu)	Notional Amount (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2005	$5.42/$6.64	15,050	$ (168)
	Weighted Average Fixed Price (Per barrel)	Notional Amount (In barrels)	Fair Value
Oil swap agreement maturing in 2005	$30.70	183	$(2,138)
	Weighted Average Floor/Ceiling Price (Per barrel)	Notional Amount (In barrels)	Fair Value
Oil collar agreements maturing in 2005	$37.79/$44.68	347	$ (608)

The following table summarizes hedge agreements entered into by Fidelity as of December 31, 2003. These agreements call for Fidelity 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 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)

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, 2004.

	2005	2006	2007	2008	2009	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$72.0	$101.8	$106.9	$161.3	$86.9	$353.6	$882.5	$930.0
Weighted average interest rate	7.9%	6.5%	8.2%	4.5%	6.2%	6.5%	6.4%	–
Variable rate	–	$ 37.0	$ 26.0	–	–	–	$ 63.0	$ 62.2
Weighted average interest rate	–	2.3%	2.3%	–	–	–	2.3%	–

For further information on derivative instruments and fair value of other financial instruments, see Item 8 – Financial Statements and Supplementary Data – Notes 5 and 6.

Foreign currency risk
MDU Brasil has a 49-percent equity method investment in an electric 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 Termoceara Generating Facility is the Brazilian Real. For further information on this investment, see Item 8 – Financial Statements and Supplementary Data – Note 2.

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 Termoceara Generating Facility's U.S. dollar denominated obligations. At December 31, 2004, these U.S. dollar denominated obligations approximated $61.4 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 Termoceara Generating Facility, would record a foreign currency loss in net income of approximately $2.3 million (after tax) based on the above U.S. dollar denominated obligations at December 31, 2004.

The investment of Centennial International in the Termoceara Generating Facility at December 31, 2004, was approximately $25.2 million.

A portion of the Termoceara 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 Termoceara Generating Facility's electric power sales contract. The Termoceara 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.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of MDU Resources Group, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) under the Securities Exchange Act of 1934. The Company's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control – Integrated Framework*.

Based on our evaluation under the framework in *Internal Control – Integrated Framework*, management concluded that the Company's internal control over financial reporting was effective as of December 31, 2004.

Management's assessment of the Company's internal control over financial reporting as of December 31, 2004, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

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

Warren L. Robinson
Executive Vice President
and Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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, 2004 and 2003, 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, 2004. Our audits also included the financial statement schedules for each of the three years in the period ended December 31, 2004, listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the 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 consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedules for each of the three years in the period ended December 31, 2004, when considered in relation to the consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Notes 1 and 8 to the consolidated financial statements, effective January 1, 2003, the Company changed its method of accounting for asset retirement obligations.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company's internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 22, 2005, expressed an unqualified opinion on management's assessment of the effectiveness of the Company's internal control over financial reporting and an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2005

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited management's assessment, included in the accompanying Management's Report on Internal Control over Financial Reporting, that MDU Resources Group, Inc. (the "Company") maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedule of the Company as of and for the year ended December 31, 2004, and our report dated February 22, 2005, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 22, 2005

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,	2004	2003	2002
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$ 776,836	$ 641,062	$ 459,409
Utility services, natural gas and oil production, construction materials and mining, independent power production and other	1,942,421	1,711,127	1,572,128
	2,719,257	2,352,189	2,031,537
Operating expenses:			
Fuel and purchased power	64,618	62,037	56,010
Purchased natural gas sold	249,924	184,171	92,528
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	158,387	141,307	129,845
Utility services, natural gas and oil production, construction materials and mining, independent power production and other	1,614,053	1,384,015	1,263,183
Depreciation, depletion and amortization	208,770	188,337	157,961
Taxes, other than income	96,681	80,250	65,893
Asset impairments (Notes 1 and 3)	6,106	–	–
	2,398,539	2,040,117	1,765,420
Operating income	320,718	312,072	266,117
Earnings from equity method investments	25,053	5,968	1,341
Other income	12,707	16,239	12,231
Interest expense	57,437	52,794	45,015
Income before income taxes	301,041	281,485	234,674
Income taxes	93,974	98,572	86,230
Income before cumulative effect of accounting change	207,067	182,913	148,444
Cumulative effect of accounting change (Note 8)	–	(7,589)	–
Net income	207,067	175,324	148,444
Dividends on preferred stocks	685	717	756
Earnings on common stock	$ 206,382	$ 174,607	$ 147,688
Earnings per common share – basic:			
Earnings before cumulative effect of accounting change	$ 1.77	$ 1.64	$ 1.39
Cumulative effect of accounting change	–	(.07)	–
Earnings per common share – basic	$ 1.77	$ 1.57	$ 1.39
Earnings per common share – diluted:			
Earnings before cumulative effect of accounting change	$ 1.76	$ 1.62	$ 1.38
Cumulative effect of accounting change	–	(.07)	–
Earnings per common share – diluted	$ 1.76	$ 1.55	$ 1.38
Dividends per common share	$ .7000	$ .6600	$ .6266
Weighted average common shares outstanding – basic	116,482	111,483	106,115
Weighted average common shares outstanding – diluted	117,411	112,460	106,863
Pro forma amounts assuming retroactive application of accounting change:			
Net income	$ 207,067	$ 182,913	$ 146,052
Earnings per common share – basic	$ 1.77	$ 1.64	$ 1.37
Earnings per common share – diluted	$ 1.76	$ 1.62	$ 1.36

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

CONSOLIDATED BALANCE SHEETS

December 31,	2004	2003
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 99,377	$ 86,341
Receivables, net	440,903	357,677
Inventories	143,880	114,051
Deferred income taxes	2,874	3,104
Prepayments and other current assets	41,144	52,367
	728,178	613,540
Investments	120,555	44,975
Property, plant and equipment (Note 1)	3,931,428	3,584,038
Less accumulated depreciation, depletion and amortization	1,358,723	1,187,105
	2,572,705	2,396,933
Deferred charges and other assets:		
Goodwill (Note 3)	199,743	199,427
Other intangible assets, net (Note 3)	22,269	18,814
Other	90,071	106,903
	312,083	325,144
	$3,733,521	$3,380,592
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 72,046	$ 27,646
Accounts payable	184,993	150,316
Taxes payable	28,372	15,358
Dividends payable	21,449	19,442
Other accrued liabilities	142,233	101,299
	449,093	314,061
Long-term debt (Note 7)	873,441	939,450
Deferred credits and other liabilities:		
Deferred income taxes	494,589	444,779
Other liabilities	235,385	231,666
	729,974	676,445
Commitments and contingencies (Notes 15, 17 and 18)		
Stockholders' equity:		
Preferred stocks (Note 9)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 10)		
Authorized – 250,000,000 shares, $1.00 par value		
Issued – 118,586,065 shares in 2004 and 113,716,632 shares in 2003	118,586	113,717
Other paid-in capital	863,449	757,787
Retained earnings	699,095	575,287
Accumulated other comprehensive loss	(11,491)	(7,529)
Treasury stock at cost – 359,281 shares	(3,626)	(3,626)
Total common stockholders' equity	1,666,013	1,435,636
Total stockholders' equity	1,681,013	1,450,636
	$3,733,521	$3,380,592

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

CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

Years ended December 31, 2004, 2003 and 2002

	Common Stock		Other	Retained	Accumulated Other Compre-hensive	Treasury Stock		
	Shares	Amount	Paid-in Capital	Earnings	Income (Loss)	Shares	Amount	Total
				(In thousands, except shares)				
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	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 (pre-split)	1,442,220	1,442	45,260	–	–	–	–	46,702
Three-for-two common stock split (Note 10)	37,862,129	37,862	(37,862)	–	–	(119,760)	–	–
Issuance of common stock (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
Comprehensive income:								
Net income	–	–	–	207,067	–	–	–	207,067
Other comprehensive income (loss), net of tax –								
Net unrealized loss on derivative instruments qualifying as hedges	–	–	–	–	(1,032)	–	–	(1,032)
Minimum pension liability adjustment	–	–	–	–	(3,782)	–	–	(3,782)
Foreign currency translation adjustment	–	–	–	–	852	–	–	852
Total comprehensive income	–	–	–	–	–	–	–	203,105
Dividends on preferred stocks	–	–	–	(685)	–	–	–	(685)
Dividends on common stock	–	–	–	(82,574)	–	–	–	(82,574)
Issuance of common stock	4,869,433	4,869	105,662	–	–	–	–	110,531
Balance at December 31, 2004	118,586,065	$118,586	$863,449	$699,095	$(11,491)	(359,281)	$(3,626)	$1,666,013

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

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31,	2004	2003	2002
		(In thousands)	
Operating activities:			
Net income	$ 207,067	$ 175,324	$ 148,444
Cumulative effect of accounting change	–	7,589	–
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	208,770	188,337	157,961
Earnings, net of distributions, from equity method investments	(22,261)	(4,020)	(1,341)
Deferred income taxes	33,163	64,587	30,759
Asset impairments	6,106	–	–
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(64,168)	(9,698)	(18,296)
Inventories	(23,799)	(13,023)	6,537
Other current assets	9,659	(13,383)	(5,562)
Accounts payable	30,319	2,748	11,600
Other current liabilities	44,172	10,486	(9,499)
Other noncurrent changes	4,043	9,450	5,728
Net cash provided by operating activities	433,071	418,397	326,331
Investing activities:			
Capital expenditures	(337,688)	(313,053)	(276,776)
Acquisitions, net of cash acquired	(37,138)	(132,653)	(92,657)
Net proceeds from sale or disposition of property	20,518	14,439	16,217
Investments	(54,265)	2,491	(4,666)
Proceeds from notes receivable	22,000	7,812	4,000
Net cash used in investing activities	(386,573)	(420,964)	(353,882)
Financing activities:			
Net change in short-term borrowings	–	(20,000)	20,000
Issuance of long-term debt	15,449	219,895	129,072
Repayment of long-term debt	(38,021)	(105,740)	(82,523)
Retirement of preferred stock	–	–	(100)
Proceeds from issuance of common stock	70,129	568	55,134
Dividends paid	(81,019)	(73,371)	(68,287)
Net cash provided by (used in) financing activities	(33,462)	21,352	53,296
Increase in cash and cash equivalents	13,036	18,785	25,745
Cash and cash equivalents – beginning of year	86,341	67,556	41,811
Cash and cash equivalents – end of year	$ 99,377	$ 86,341	$ 67,556

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

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1 – SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of presentation

The consolidated financial statements of the 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, 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, independent power production, and other are nonregulated. For further descriptions of the Company's businesses, see Note 13. The statements also include the ownership interests in the assets, liabilities and expenses of two jointly owned electric generating facilities.

The Company uses the equity method of accounting for certain investments. For more information on the Company's equity method investments, see Note 2.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the 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 SFAS No. 71, "Accounting for the Effects of Certain Types 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.

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, 2004 and 2003, was $6.8 million and $8.1 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 was $24.9 million and $19.6 million at December 31, 2004 and 2003, respectively. The remainder of natural gas in underground storage was included in other assets and was $43.3 million and $42.6 million at December 31, 2004 and 2003, respectively.

Inventories

Inventories, other than natural gas in underground storage for the Company's regulated operations, consisted primarily of aggregates held for resale of $71.0 million and $54.7 million, materials and supplies of $31.0 million and $27.2 million, and other inventories of $17.0 million and $12.6 million, as of December 31, 2004 and 2003, 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. Leased mineral rights at the Company's construction materials and mining business were reclassified from other intangible assets, net, to property, plant and equipment, as discussed in new accounting standards in this note. 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 this note, 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 $6.2 million, $7.4 million and $7.6 million in 2004, 2003 and 2002, 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, 2004 and 2003, was as follows:

	2004	2003	Estimated Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	**$ 650,902**	$ 639,893	4-50
Natural gas distribution:			
Natural gas distribution plant	**264,496**	252,591	4-40
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities	**358,853**	340,841	8-104
Nonregulated:			
Utility services:			
Land	**2,533**	2,505	–
Buildings and improvements	**10,257**	10,123	3-40
Machinery, vehicles and equipment	**63,586**	58,843	2-10
Other	**6,224**	5,400	3-10
Pipeline and energy services:			
Natural gas gathering and other facilities	**132,067**	119,613	3-20
Energy services	**1,480**	1,339	3-15
Natural gas and oil production:			
Natural gas and oil properties	**973,604**	862,839	*
Other	**9,021**	8,518	3-7
Construction materials and mining:			
Land	**91,610**	89,545	–
Buildings and improvements	**51,309**	48,907	3-40
Machinery, vehicles and equipment	**658,355**	569,295	1-23
Construction in progress	**16,545**	14,392	–
Aggregate reserves	**372,649**	358,260	**
Independent power production:			
Electric generation	**154,631**	153,944	10-30
Construction in progress	**93,953**	29,805	–
Land	**375**	375	–
Other	**1,643**	3	3-7
Other:			
Land	**3,044**	1,626	–
Other	**14,291**	15,381	3-20
Less accumulated depreciation, depletion and amortization	**1,358,723**	1,187,105	
Net property, plant and equipment	**$2,572,705**	$2,396,933	

** Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $.98, $.89, and $.80 for the years ended December 31, 2004, 2003 and 2002, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $69.0 million and $104.3 million were excluded from amortization at December 31, 2004 and 2003, respectively.*

*** Depleted 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 impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In the third quarter of 2004, the Company recognized a $2.1 million ($1.3 million after tax) adjustment reflecting the reduction in value of certain gathering facilities in the Gulf Coast region at the pipeline and energy services segment. No impairment losses were recorded in 2003 and 2002. 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. 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 the third quarter of 2004, the Company recognized a goodwill impairment at the pipeline and energy services segment. For more information on the goodwill impairment and 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 SEC, and the cost 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, 2004 and 2003, 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, 2004, 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, 2004, in total and by year in which such costs were incurred:

		Year Costs Incurred			
	Total	2004	2003	2002	2001 and prior
			(In thousands)		
Acquisition	$34,169	$ 6,708	$ 481	$15,493	$11,487
Development	22,582	16,259	4,559	1,764	–
Exploration	5,228	4,681	547	–	–
Capitalized interest	7,005	2,252	1,839	2,914	–
Total costs not subject to amortization	$68,984	$29,900	$7,426	$20,171	$11,487

Costs not subject to amortization as of December 31, 2004, 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 and an enhanced recovery development project in the Cedar Creek Anticline in southeastern Montana. The Company expects that the majority of these costs will be evaluated within the next 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 and, where applicable, revenues are recognized under Emerging Issues Task Force Issue No. 91-6, "Revenue Recognition of Long-Term Power Sales Contracts," ratably over the terms of the related contract. 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. If a loss is anticipated on a contract, the loss is immediately recognized. Costs in excess of billings on uncompleted contracts of $31.9 million and $31.8 million at December 31, 2004 and 2003, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of $32.2 million and $20.4 million at December 31, 2004 and 2003, respectively, represent billings in excess of revenues recognized and were 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 $40.9 million and $34.3 million at December 31, 2004 and 2003, 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 that natural gas and oil price derivative instruments and interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. 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.

Asset retirement obligations

In 2003, the Company adopted SFAS No. 143, which requires the Company 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 Company 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, the Company either settles the obligation for the recorded amount or incurs a gain or loss. For more information on asset retirement obligations, see Note 8.

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 $15.5 million and $10.5 million at December 31, 2004 and 2003, respectively, which is included in prepayments and other current assets.

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 above the primary automobile and general liability policies 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 for claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities resulting from the Company's adoption of 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 10.

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, 2004, 2003 and 2002, 36,000 shares, 209,805 shares and 3,674,925 shares, respectively, with an average exercise price of $25.70, $24.56 and $20.08, 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, 2004, 2003 and 2002, 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 years ended December 31, 2004 and 2003, was $18,000 and $41,000, respectively (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 Accounting Principles Board (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.

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, 2004, 2003 and 2002, 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:

	2004	2003	2002
	(In thousands, except per share amounts)		
Earnings on common stock, as reported	**$206,382**	$174,607	$147,688
Stock-based compensation expense included in reported earnings, net of related tax effects	**18**	41	–
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects	**(62)**	(2,139)	(2,862)
Pro forma earnings on common stock	**$206,338**	$172,509	$144,826
Earnings per common share – basic – as reported:			
Earnings before cumulative effect of accounting change	**$ 1.77**	$ 1.64	$ 1.39
Cumulative effect of accounting change	**–**	(.07)	–
Earnings per common share – basic	**$ 1.77**	$ 1.57	$ 1.39
Earnings per common share – basic – pro forma:			
Earnings before cumulative effect of accounting change	**$ 1.77**	$ 1.62	$ 1.36
Cumulative effect of accounting change	**–**	(.07)	–
Earnings per common share – basic	**$ 1.77**	$ 1.55	$ 1.36
Earnings per common share – diluted – as reported:			
Earnings before cumulative effect of accounting change	**$ 1.76**	$ 1.62	$ 1.38
Cumulative effect of accounting change	**–**	(.07)	–
Earnings per common share – diluted	**$ 1.76**	$ 1.55	$ 1.38
Earnings per common share – diluted – pro forma:			
Earnings before cumulative effect of accounting change	**$ 1.76**	$ 1.60	$ 1.36
Cumulative effect of accounting change	**–**	(.07)	–
Earnings per common share – diluted	**$ 1.76**	$ 1.53	$ 1.36

For more information on the Company's stock-based compensation, see Note 11.

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 the electric power sales contract 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,	2004	2003	2002
		(In thousands)	
Interest, net of amount capitalized	**$50,236**	$47,474	$37,788
Income taxes	**$50,487**	$31,737	$60,988

Reclassifications

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

New accounting standards

FIN 46 (revised) In December 2003, the FASB issued FIN 46 (revised), which replaced 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.

The Company evaluated the provisions of FIN 46 (revised) and determined that the Company does not have any controlling financial interests in any variable interest entities and, therefore, is not required to consolidate any variable interest entities in its financial statements. The adoption of FIN 46 (revised) did not have an effect on the Company's financial position or results of operations.

FSP Nos. FAS 106-1 and FAS 106-2 In January 2004, the FASB issued FSP No. FAS 106-1. FSP 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 2003 Medicare Act.

In May 2004, the FASB issued FSP No. FAS 106-2. FSP No. FAS 106-2 requires (a) that the effects of the federal subsidy be considered an actuarial gain and recognized in the same manner as other actuarial gains and losses and (b) certain disclosures for employers that sponsor postretirement health care plans that provide prescription drug benefits.

The Company provides prescription drug benefits to certain eligible employees. The Company elected the one-time deferral of accounting for the effects of the 2003 Medicare Act in the quarter ended March 31, 2004, the first period in which the plan's accounting for the effects of the 2003 Medicare Act normally would have been reflected in the Company's financial statements.

During the second quarter of 2004, the Company adopted FSP No. FAS 106-2 retroactive to the beginning of the year. The Company and its actuarial advisors determined that benefits provided to certain participants are expected to be at least actuarially equivalent to Medicare Part D (the federal prescription drug benefit), and, accordingly, the Company expects to be entitled to a federal subsidy. The expected federal subsidy reduced the APBO at January 1, 2004, by approximately $3.2 million, and net periodic benefit cost for 2004 by approximately $285,000 (as compared with the amount calculated without considering the effects of the subsidy). In addition, the Company expects a reduction in future participation in the postretirement plans, which further reduced the APBO at January 1, 2004, by approximately $12.7 million and net periodic benefit cost for 2004 by approximately $1.3 million.

FSP Nos. FAS 141-1 and FAS 142-1 In April 2004, the FASB issued FSP Nos. FAS 141-1 and FAS 142-1. FSP Nos. FAS 141-1 and FAS 142-1 amend SFAS No. 141, "Business Combinations," and SFAS No. 142 to clarify that certain mineral rights held by mining entities that are not within the scope of SFAS No. 19 be classified as tangible assets rather than intangible assets. The Company adopted FSP Nos. FAS 141-1 and FAS 142-1 in the second quarter of 2004. FSP Nos. FAS 141-1 and FAS 142-1 required reclassification of the Company's leasehold rights at its construction materials and mining operations from other intangible assets, net, to property, plant and equipment, as well as changes to Notes to Consolidated

Financial Statements. FSP Nos. FAS 141-1 and FAS 142-1 affected the asset classification in the consolidated balance sheet and associated footnote disclosure only, so the reclassifications did not affect the Company's stockholders' equity, cash flows or results of operations.

FSP No. FAS 142-2 In September 2004, the FASB Staff issued FSP No. FAS 142-2. FSP No. FAS 142-2 indicates that the exception in SFAS No. 142 does not change the accounting prescribed in SFAS No. 19 including the balance sheet classification of drilling and mineral rights of oil and gas producing entities and, as a result, the contractual mineral rights should continue to be classified as part of property, plant and equipment. FSP No. FAS 142-2 did not have an effect on the Company's financial position, results of operations or cash flows.

SAB No. 106 In September 2004, the SEC issued SAB No. 106 which is an interpretation regarding the application of SFAS No. 143 by oil and gas producing companies following the full-cost accounting method. SAB No. 106 clarifies that the future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet should be excluded from the computation of the present value of estimated future net revenues for purposes of the full-cost ceiling calculation. SAB No. 106 also states that a company is expected to disclose in the financial statement footnotes and MD&A how the company's calculation of the ceiling test and depreciation, depletion and amortization are affected by the adoption of SFAS No. 143. SAB No. 106 shall be applied to all entities subject to SAB No. 106 as of the beginning of the first quarter after October 4, 2004. The adoption of SAB No. 106 is not expected to have a material effect on the Company's financial position or results of operations.

SFAS No. 123 (revised) In December 2004, the FASB issued SFAS No. 123 (revised). SFAS No. 123 (revised) revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the fair value of share-based payments granted to employees. SFAS No. 123 (revised) requires a company to record compensation expense for all awards granted after the date of adoption of SFAS No. 123 (revised) and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. SFAS No. 123 (revised) is effective as of the beginning of the first interim or annual reporting period that begins after June 15, 2005. The Company is evaluating the effects of the adoption of SFAS No. 123 (revised).

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 (losses) on derivative instruments qualifying as hedges, minimum pension liability adjustments and foreign currency translation adjustments. For more information on derivative instruments, see Note 5.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2004, 2003 and 2002, were as follows:

	2004	2003	2002
		(In thousands)	
Other comprehensive income (loss):			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized loss on derivative instruments arising during the period, net of tax of $2,734, $2,132 and $2,903 in 2004, 2003 and 2002, respectively	**$(4,367)**	$(3,335)	$ (4,541)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $2,132, $2,903 and $1,448 in 2004, 2003 and 2002, respectively	**(3,335)**	(4,541)	2,218
Net unrealized gain (loss) on derivative instruments qualifying as hedges	**(1,032)**	1,206	(6,759)
Minimum pension liability adjustment, net of tax of $2,406, $38 and $2,876 in 2004, 2003 and 2002, respectively	**(3,782)**	21	(4,464)
Foreign currency translation adjustment	**852**	1,048	(799)
Total other comprehensive income (loss)	**$(3,962)**	$ 2,275	$(12,022)

The after-tax components of accumulated other comprehensive loss as of December 31, 2004, 2003 and 2002, were as follows:

	Net Unrealized Loss on Derivative Instruments Qualifying as Hedges	Minimum Pension Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Loss
		(In thousands)		
Balance at December 31, 2002	$(4,541)	$(4,464)	$ (799)	$ (9,804)
Balance at December 31, 2003	$(3,335)	$(4,443)	$ 249	$ (7,529)
Balance at December 31, 2004	**$(4,367)**	**$(8,225)**	**$1,101**	**$(11,491)**

NOTE 2 – EQUITY METHOD INVESTMENTS

The Company has a number of equity method investments including MPX, Carib Power and Hartwell. The Company assesses its equity method investments for impairment whenever events or changes in circumstances indicate that such carrying values may not be recoverable. None of the Company's equity method investments have been impaired and, accordingly, no impairment losses have been recorded in the accompanying consolidated financial statements or related equity method investment balances.

MDU Brasil has a 49 percent interest in MPX, which was formed in August 2001 when MDU Brasil entered into a joint venture agreement with a Brazilian firm. MPX, through a wholly owned subsidiary, owns and operates the Termoceara Generating Facility in the Brazilian state of Ceara. Petrobras, the Brazilian state-controlled energy company, entered into a contract to purchase all of the capacity and market all of energy from the Termoceara Generating Facility. The first phase of the electric power sales contract with Petrobras for 110 megawatts expires in November 2007 and the portion of the contract for the remaining 110 megawatts expires in May 2008. Petrobras also is under contract to supply natural gas to the Termoceara Generating Facility during the term of the electric power sales contract. This natural gas supply contract is renewable by a wholly owned subsidiary of MPX for an additional 13 years.

During 2004, Petrobras initiated discussions with a number of owners of thermoelectric plants, including MPX, regarding a possible renegotiation of their related power purchase agreements or buyout of the generating plants. On January 13, 2005, Petrobras obtained a Brazilian court order permitting it to cease making monthly capacity payments to MPX and to instead deposit the payments into a court account until the matter is resolved. On February 2, 2005, the court revoked its January 13, 2005, order and stated that MPX could withdraw the amounts deposited by Petrobras. This decision was upheld on appeal on February 17, 2005. Under the existing contract, Petrobras agreed to jointly market all of the facility's energy, and in the event that the facility's revenues are insufficient to cover its costs during certain periods, to make certain monthly contingency payments. Petrobras has stated that, because of structural changes in the Brazilian electric power markets since the contract was signed in 2001, the contingency payments had become permanent payment obligations entitling Petrobras to renegotiate the contract. The contract contains a dispute resolution provision which creates a 30-day period for accelerated negotiations. In the event that the parties do not reach agreement during the 30-day period, the dispute would be resolved in arbitration.

The Termoceara Generating Facility generates electricity based upon economic dispatch and available gas supplies. Under current conditions, including, in particular, existing constraints in the region's gas supply infrastructure, the Company does not expect the facility to generate a significant amount of energy at least through 2006.

The functional currency for the Termoceara Generating Facility is the Brazilian Real. The electric power sales contract 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. The Company's 49 percent share of the gain (loss) from the change in fair value of the embedded derivative in the electric power sales contract and the Company's 49 percent share of the foreign currency gain (loss) resulting from an increase (decrease) in value of the Brazilian Real versus the U.S. dollar for the years ended December 31, were as follows:

	2004	2003	2002
		(In thousands)	
Company's 49 percent share of the gain (loss) from the change in fair value of the embedded derivative in the electric power sales contract (after tax)	**$2,451**	$(11,282)	$13,592
Company's 49 percent share of the foreign currency gain (loss) resulting from the change in value of the Brazilian Real versus the U.S. dollar (after tax)	**$1,871**	$ 2,757	$ (9,392)

Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX. For more information on this guarantee, see Note 18.

On February 26, 2004, Centennial International acquired 49.99 percent of Carib Power. Carib Power, through a wholly owned subsidiary, owns a 225-megawatt natural gas-fired electric generating facility located in Trinidad and Tobago. The Trinity Generating Facility sells its output to the T&TEC, the governmental entity responsible for the transmission, distribution and administration of electrical power to the national electrical grid of Trinidad and Tobago. The power purchase agreement expires in September 2029. T&TEC also is under contract to supply natural gas to the Trinity Generating Facility during the term of the power purchase contract. The functional currency for the Trinity Generating Facility is the U.S. dollar.

On September 28, 2004, Centennial Resources, through wholly owned subsidiaries, acquired a 50-percent ownership interest in a 310-megawatt natural gas-fired electric generating facility. This facility is located in Hartwell, Georgia. The Hartwell Generating Facility sells its output under a power purchase agreement with Oglethorpe that expires in May 2019. American National Power, a wholly owned subsidiary of International Power of the United Kingdom, holds the remaining 50-percent ownership interest and is the operating partner for the facility.

At December 31, 2004, MPX, Carib Power and Hartwell had total assets of $334.2 million and long-term debt of $224.9 million. The Company's investment in the Termoceara, Trinity and Hartwell Generating Facilities was approximately $65.7 million, including undistributed earnings of $26.6 million at December 31, 2004. The Company's investment in the Termoceara Generating Facility was approximately $25.2 million, including undistributed earnings of $4.6 million at December 31, 2003.

NOTE 3 – GOODWILL AND OTHER INTANGIBLE ASSETS

The changes in the carrying amount of goodwill for the year ended December 31, 2004, were as follows:

	Balance as of January 1, 2004	Goodwill Acquired During the Year*	Goodwill Impaired During the Year	Balance as of December 31, 2004
		(In thousands)		
Electric	$ –	$ –	$ –	$ –
Natural gas distribution	–	–	–	–
Utility services	62,604	28	–	62,632
Pipeline and energy services	9,494	–	(4,030)	5,464
Natural gas and oil production	–	–	–	–
Construction materials and mining	120,198	254	–	120,452
Independent power production	7,131	4,064	–	11,195
Other	–	–	–	–
Total	$199,427	$4,346	$(4,030)	$199,743

* *Includes purchase price adjustments related to acquisitions acquired in a prior period.*

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	7,131	–	7,131
Other	–	–	–
Total	$190,999	$8,428	$199,427

* *Includes purchase price adjustments related to acquisitions acquired in a prior period.*

Innovatum, which specializes in cable and pipeline magnetization and location, developed a hand-held locating device that can detect both magnetic and plastic materials, including unexploded ordnance. Innovatum was working with, and had demonstrated the device to, a Department of Defense contractor and had also met with individuals from the Department of Defense, to discuss the possibility of using the hand-held locating device in their operations. In the third quarter of 2004, after communications with the Department of Defense, and delays in further testing resulting from a Department of Defense request to enhance the hand-held locating device, Innovatum decreased its expected future cash flows from the hand-held locating device. This decrease, coupled with the continued downturn in the telecommunications and energy industries, resulted in a revised earnings forecast for Innovatum, and as a result, a goodwill impairment loss of $4.0 million (before and after tax), which was included in asset impairments, was recognized in the third quarter of 2004. Innovatum, a reporting unit for goodwill impairment testing, is part of the pipeline and energy services segment. The fair value of Innovatum was estimated using the expected present value of future cash flows.

As discussed in Note 1, the Company reclassified its leasehold rights at its construction materials and mining operations from other intangible assets, net, to property, plant and equipment.

Other intangible assets at December 31, 2004 and 2003 were as follows:

	2004	2003
	(In thousands)	
Amortizable intangible assets:		
Acquired contracts	$15,041	$12,656
Accumulated amortization	(5,013)	(1,944)
	10,028	10,712
Noncompete agreements	10,575	12,075
Accumulated amortization	(8,186)	(9,690)
	2,389	2,385
Other	9,535	5,078
Accumulated amortization	(534)	(321)
	9,001	4,757
Unamortizable intangible assets	851	960
Total	$22,269	$18,814

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, 2004, 2003 and 2002, was $3.8 million, $2.2 million and $757,000, respectively. Estimated amortization expense for amortizable intangible assets is $2.8 million in 2005, $2.0 million in 2006, 2007 and 2008, $1.9 million in 2009 and $10.7 million thereafter.

NOTE 4 – REGULATORY ASSETS AND LIABILITIES

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

	2004	2003
	(In thousands)	
Regulatory assets:		
Deferred income taxes	$ 39,212	$ 37,072
Natural gas costs recoverable through rate adjustments	15,534	10,519
Plant costs	12,838	2,697
Long-term debt refinancing costs	3,531	4,519
Postretirement benefit costs	507	562
Other	7,225	7,159
Total regulatory assets	78,847	62,528
Regulatory liabilities:		
Plant removal and decommissioning costs	78,525	76,176
Liabilities for regulatory matters	18,853	11,970
Taxes refundable to customers	15,660	18,973
Deferred income taxes	15,192	10,663
Other	3,676	658
Total regulatory liabilities	131,906	118,440
Net regulatory position	$(53,059)	$(55,912)

As of December 31, 2004, a large portion of the Company's regulatory assets, other than certain deferred income taxes, was being reflected in rates charged to customers and is being recovered over the next one to 18 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

Derivative instruments (including certain derivative instruments embedded in other contracts) are required to be recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative instrument's fair value are 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.

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; if the derivative instrument expires or is sold, terminated or exercised; 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, 2004, Fidelity held derivative instruments designated as cash flow hedging instruments.

Hedging activities

Fidelity 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 its 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, 2004, 2003 and 2002, the amount of hedge ineffectiveness, which was included in operating revenues, was immaterial. For the years ended December 31, 2004, 2003 and 2002, Fidelity 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, 2004, the maximum term of Fidelity's swap and collar agreements, in which Fidelity is hedging its exposure to the variability in future cash flows for forecasted transactions, is 12 months. Fidelity estimates that over the next 12 months, net losses of approximately $4.4 million will be reclassified from accumulated other comprehensive loss into earnings, subject to changes in natural gas and oil market prices, as the hedged transactions affect earnings.

NOTE 6 – FAIR VALUE OF OTHER FINANCIAL INSTRUMENTS

The estimated fair value of the Company's long-term debt is based on quoted market prices of the same or similar issues. The estimated fair values of the Company's natural gas and oil price swap and collar agreements were included in current liabilites at December 31, 2004 and 2003. The estimated fair values of the Company's natural gas and oil price swap and collar agreements 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 and natural gas and oil price swap and collar agreements at December 31 was as follows:

	2004		2003	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$945,487	$992,172	$967,096	$1,012,547
Natural gas and oil price swap and collar agreements	$ (7,101)	$ (7,101)	$ (5,467)	$ (5,467)

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 – LONG-TERM DEBT AND INDENTURE PROVISIONS

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

	2004	2003
	(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 7.75%, due on dates ranging from April 1, 2007 to April 1, 2012	95,000	110,000
Senior Note, 5.98%, due December 15, 2033	30,000	30,000
Total first mortgage bonds and notes	145,850	160,850
Senior notes at a weighted average rate of 6.23%, due on dates ranging from January 18, 2005 to July 1, 2019	728,500	718,000
Commercial paper at a weighted average rate of 2.28%, supported by revolving credit agreements	63,000	72,500
Term credit agreements at a weighted average rate of 6.68%, due on dates ranging from January 25, 2005 to December 1, 2013	8,172	14,286
Pollution control note obligation, 6.20%, paid in 2004	–	1,500
Discount	(35)	(40)
Total long-term debt	945,487	967,096
Less current maturities	72,046	27,646
Net long-term debt	$873,441	$939,450

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2004, aggregate $72.0 million in 2005; $138.8 million in 2006; $132.9 million in 2007; $161.3 million in 2008; $86.9 million in 2009 and $353.6 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, 2004.

MDU Resources Group, Inc.

The Company has a revolving credit agreement with various banks totaling $90 million at December 31, 2004. There were no amounts outstanding under the credit agreement at December 31, 2004 and 2003. The credit agreement supports the Company's $75 million commercial paper program. Under the Company's commercial paper program, $37.0 million and $40.0 million were outstanding at December 31, 2004 and 2003, respectively, which was classified as long-term debt. The commercial paper borrowings classified as long-term debt are intended to be refinanced on a long-term basis through continued commercial paper borrowings and as further supported by the credit agreement, which expires on July 18, 2006.

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. MDU Resources was in compliance with these covenants and met the required conditions at December 31, 2004.

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

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its Indenture of Mortgage. Generally, those restrictions require MDU Resources to fund $1.43 of unfunded property or use $1.00 of refunded bonds for each dollar of indebtedness incurred under the Indenture and, in some cases, to certify to the trustee 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 tests, as of December 31, 2004, the Company could have issued approximately $343 million of additional first mortgage bonds.

Approximately $419.7 million of the Company's net electric and natural gas distribution properties at December 31, 2004, 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 has three revolving credit agreements with various banks and institutions that support $335 million of Centennial's $350 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2004 or 2003. Under the Centennial commercial paper program, $26.0 million and $32.5 million were outstanding at December 31, 2004 and 2003, 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. One of these credit agreements is for $300 million and expires on August 17, 2007, and another agreement is for $25 million and expires on April 30, 2007. Centennial intends to negotiate the extension or replacement of these agreements prior to their maturities. The third agreement is an uncommitted line for $10 million, which was effective on January 25, 2005, and may be terminated by the bank at any time.

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, 2004 and 2003. The ability to request additional borrowings under this master shelf agreement expires on February 28, 2005. The Company is in discussion regarding potential renewal of this facility. 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, 2004.

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 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, 2004 and 2003. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2005.

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, 2004.

NOTE 8 – ASSET RETIREMENT OBLIGATIONS

The Company adopted SFAS No. 143 on January 1, 2003. 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, which is included in other liabilities, for the years ended December 31 was as follows:

	2004	2003
	(In thousands)	
Balance at beginning of year	**$34,633**	$29,997
Liabilities incurred	**3,718**	2,405
Liabilities acquired	**178**	1,803
Liabilities settled	**(2,286)**	(1,555)
Accretion expense	**1,931**	1,906
Revisions in estimates	**(824)**	77
Balance at end of year	**$37,350**	$34,633

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2004 and 2003, was $5.2 million and $5.1 million, respectively.

NOTE 9 – PREFERRED STOCKS

Preferred stocks at December 31 were as follows:

	2004	2003
	(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:		
4.50% Series – 100,000 shares	**$10,000**	$10,000
4.70% Series – 50,000 shares	**5,000**	5,000
Total preferred stocks	**$15,000**	$15,000

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 10 – 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.

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, 2002, 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, 2004, there were 12.1 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

In 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 11 – 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, 2004, 2003 and 2002, 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, 2004, 2003 and 2002, and changes during the years then ended were as follows:

	2004		2003		2002	
	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price	Shares	Weighted Average Exercise Price
Balance at beginning of year	**4,182,456**	**$19.09**	4,861,268	$18.58	5,208,311	$18.60
Granted	**–**	**–**	27,015	17.29	160,605	19.15
Forfeited	**(382,942)**	**19.64**	(188,486)	20.05	(453,840)	19.77
Exercised	**(1,237,830)**	**18.49**	(517,341)	13.88	(53,808)	12.20
Balance at end of year	**2,561,684**	**19.29**	4,182,456	19.09	4,861,268	18.58
Exercisable at end of year	**1,700,223**	**$18.73**	611,404	$15.06	1,135,050	$14.56

Summarized information about stock options outstanding and exercisable as of December 31, 2004, 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	11,076	2.3	$10.69	11,076	$10.69
13.01 – 17.00	374,050	3.4	14.20	371,404	14.19
17.01 – 21.00	1,977,433	6.2	19.77	1,243,108	19.78
21.01 – 25.70	199,125	6.2	24.55	74,635	24.97
Balance at end of year	2,561,684	5.8	19.29	1,700,223	18.73

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:

	2004	2003	2002
Weighted average fair value of options at grant date	**–**	$4.67	$5.38
Weighted average risk-free interest rate	**–**	3.91%	5.14%
Weighted average expected price volatility	**–**	32.28%	30.80%
Weighted average expected dividend yield	**–**	3.43%	3.43%
Expected life in years	**–**	7	7

In addition, prior to 2002 the Company granted restricted stock awards under a long-term incentive plan and deferred compensation agreements. The restricted stock awards granted vest to the participants at various times ranging from one year 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 Company also has granted stock awards totaling 35,205 shares, 31,855 shares and 21,390 shares in 2004, 2003 and 2002, respectively, under a nonemployee director stock compensation plan. The weighted average grant date fair value of the stock grants was $23.61, $21.40 and $19.20, in 2004, 2003 and 2002, 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 $3.4 million, $4.8 million and $5.2 million in 2004, 2003 and 2002, respectively.

In 2004 and 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	59,224
February 2003	2003-2005	54,180
February 2004	2004-2006	189,337

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 years ended December 31, 2004 and 2003, was $2.5 million and $879,000, respectively.

The Company is authorized to grant options, restricted stock and stock for up to 14.7 million shares of common stock and has granted options, restricted stock and stock on 5.8 million shares through December 31, 2004.

NOTE 12 – INCOME TAXES

The components of income before income taxes for each of the years ended December 31 were as follows:

	2004	2003	2002
		(In thousands)	
United States	**$280,764**	$278,143	$233,536
Foreign	**20,277**	3,342	1,138
Income before income taxes	**$301,041**	$281,485	$234,674

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

	2004	2003	2002
		(In thousands)	
Current:			
Federal	**$47,625**	$26,313	$46,389
State	**12,231**	7,408	9,082
Foreign	**955**	264	–
	60,811	33,985	55,471
Deferred:			
Income taxes –			
Federal	**28,556**	55,660	26,373
State	**5,422**	9,861	4,632
Foreign	**(223)**	(338)	338
Investment tax credit	**(592)**	(596)	(584)
	33,163	64,587	30,759
Total income tax expense	**$93,974**	$98,572	$86,230

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

	2004	2003
	(In thousands)	
Deferred tax assets:		
Regulatory matters	**$ 39,212**	$ 37,072
Accrued pension costs	**18,754**	12,122
Asset retirement obligations	**12,197**	7,017
Deferred compensation	**9,938**	9,090
Bad debts	**2,266**	3,188
Deferred investment tax credit	**724**	954
Other	**29,237**	21,269
Total deferred tax assets	**112,328**	90,712
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**450,237**	406,589
Basis differences on natural gas and oil producing properties	**124,788**	105,826
Regulatory matters	**15,192**	10,663
Other	**13,826**	9,309
Total deferred tax liabilities	**604,043**	532,387
Net deferred income tax liability	**$(491,715)**	$(441,675)

As of December 31, 2004 and 2003, 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, 2003, to December 31, 2004, to deferred income tax expense:

	2004
	(In thousands)
Change in net deferred income tax liability from the preceding table	**$ 50,040**
Deferred taxes associated with acquisitions	**(16,189)**
Other	**(688)**
Deferred income tax expense for the period	**$ 33,163**

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,	2004		2003		2002	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$105,364	35.0	$98,520	35.0	$82,136	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit	11,468	3.8	11,857	4.2	10,279	4.4
Audit resolution	(8,818)	(2.9)	–	–	–	–
Foreign operations	(5,648)	(1.9)	(832)	(.3)	177	–
Depletion allowance	(3,418)	(1.2)	(3,117)	(1.1)	(2,200)	(.9)
Renewable electricity production credit	(3,404)	(1.1)	(3,395)	(1.2)	–	–
Other items	(1,570)	(.5)	(4,461)	(1.6)	(4,162)	(1.8)
Total income tax expense	$ 93,974	31.2	$98,572	35.0	$86,230	36.7

In 2004, the Company resolved federal and related state income tax matters for the 1998 through 2000 tax years. The Company reflected the effects of this tax resolution and, in addition, reversed liabilities that had previously been provided and were deemed to be no longer required, which resulted in a benefit of $8.3 million (after tax), including interest.

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. The cumulative undistributed earnings at December 31, 2004, were approximately $22 million. The amount of unrecognized deferred tax liability associated with the undistributed earnings was approximately $5 million.

The Company has evaluated the repatriation provisions of the American Jobs Creation Act of 2004 (Act), which was enacted on October 22, 2004. The provisions of the Act permit corporations to elect an 85-percent deduction for certain qualifying dividends received during 2005 from controlled foreign corporations. The deduction is only available to the extent that the dividend is in excess of an historical base-period average and if the dividend is invested in the United States pursuant to a qualifying domestic investment plan. At this time, the Company does not anticipate that it will be receiving dividends qualifying for this election during 2005.

NOTE 13 – BUSINESS SEGMENT DATA

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. Prior to the fourth quarter of 2004, the Company reported 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. The independent power production and other operations did not individually meet the criteria to be considered a reportable segment. In the fourth quarter of 2004, the Company separated independent power production as a reportable business segment due to the significance of its operations. The Company's operations are now conducted through seven reportable segments and all prior period information has been restated to reflect this change.

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 investments in natural gas-fired electric generating facilities in Brazil and Trinidad and Tobago, 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, development 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 segment owns, builds and operates electric generating facilities in the United States and has investments in domestic and international natural resource-based projects. Electric capacity and energy produced at its power plants are sold primarily under mid- and long-term contracts to nonaffiliated entities.

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:

	2004	2003	2002
		(In thousands)	
External operating revenues:			
Electric	$ 178,803	$ 178,562	$ 162,616
Natural gas distribution	316,120	274,608	186,569
Pipeline and energy services	281,913	187,892	110,224
	776,836	641,062	459,409
Utility services	425,250	434,177	458,660
Natural gas and oil production	152,486	140,281	148,158
Construction materials and mining	1,321,626	1,104,408	962,312
Independent power production	43,059	32,261	2,998
Other	–	–	–
	1,942,421	1,711,127	1,572,128
Total external operating revenues	$2,719,257	$2,352,189	$2,031,537
Intersegment operating revenues:			
Electric	$ –	$ –	$ –
Natural gas distribution	–	–	–
Utility services	1,571	–	–
Pipeline and energy services	75,316	64,300	55,034
Natural gas and oil production	190,354	124,077	55,437
Construction materials and mining	535	–	–
Independent power production	–	–	–
Other	4,423	2,728	3,778
Intersegment eliminations	(272,199)	(191,105)	(114,249)
Total intersegment operating revenues	$ –	$ –	$ –
Depreciation, depletion and amortization:			
Electric	$ 20,199	$ 20,150	$ 19,537
Natural gas distribution	9,329	10,044	9,940
Utility services	11,113	10,353	9,871
Pipeline and energy services	17,804	15,016	14,846
Natural gas and oil production	70,823	61,019	48,714
Construction materials and mining	69,644	63,601	54,334
Independent power production	9,587	7,860	444
Other	271	294	275
Total depreciation, depletion and amortization	$ 208,770	$ 188,337	$ 157,961
Interest expense:			
Electric	$ 9,116	$ 8,013	$ 7,621
Natural gas distribution	4,292	3,936	4,364
Utility services	3,442	3,668	3,568
Pipeline and energy services	9,262	7,952	7,670
Natural gas and oil production	7,552	4,767	2,464
Construction materials and mining	20,646	18,747	18,422
Independent power production	4,354	5,850	1,100
Other	(70)	15	22
Intersegment eliminations	(1,157)	(154)	(216)
Total interest expense	$ 57,437	$ 52,794	$ 45,015
Income taxes:			
Electric	$ 4,303	$ 9,862	$ 9,501
Natural gas distribution	(3,883)	1,823	(1,325)
Utility services	(3,345)	3,905	4,781
Pipeline and energy services	7,445	11,188	12,462
Natural gas and oil production	61,261	42,993	30,604
Construction materials and mining	26,674	28,168	29,415
Independent power production	1,249	257	406
Other	270	376	386
Total income taxes	$ 93,974	$ 98,572	$ 86,230

	2004	2003	2002
		(In thousands)	
Cumulative effect of accounting change (Note 8):			
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	–	–	–
Other	–	–	–
Total cumulative effect of accounting change	$ –	$ (7,589)	$ –
Earnings on common stock:			
Electric	$ 12,790	$ 16,950	$ 15,780
Natural gas distribution	2,182	3,869	3,587
Utility services	(5,650)	6,170	6,371
Pipeline and energy services	8,944	18,158	19,097
Natural gas and oil production	110,779	63,027	53,192
Construction materials and mining	50,707	54,412	48,702
Independent power production	26,309	11,415	307
Other	321	606	652
Total earnings on common stock	$ 206,382	$ 174,607	$ 147,688
Capital expenditures:			
Electric	$ 18,767	$ 28,537	$ 27,795
Natural gas distribution	17,384	15,672	11,044
Utility services	8,470	7,820	17,242
Pipeline and energy services	38,282	93,004	21,449
Natural gas and oil production	111,506	101,698	136,424
Construction materials and mining	133,080	128,487	106,893
Independent power production	76,246	110,963	89,621
Other	4,215	1,895	6,127
Net proceeds from sale or disposition of property	(20,518)	(14,439)	(16,217)
Total net capital expenditures	$ 387,432	$ 473,637	$ 400,378
Identifiable assets:			
Electric*	$ 323,819	$ 327,899	$ 322,475
Natural gas distribution*	252,582	234,948	208,502
Utility services	230,955	221,824	230,888
Pipeline and energy services	447,302	405,904	312,858
Natural gas and oil production	685,610	602,389	554,420
Construction materials and mining	1,345,547	1,248,607	1,137,697
Independent power production	349,752	241,918	130,867
Other**	97,954	97,103	99,214
Total identifiable assets	$3,733,521	$3,380,592	$2,996,921
Property, plant and equipment:			
Electric*	$ 650,902	$ 639,893	$ 619,230
Natural gas distribution*	264,496	252,591	244,930
Utility services	82,600	76,871	70,660
Pipeline and energy services	492,400	461,793	372,420
Natural gas and oil production	982,625	871,357	755,788
Construction materials and mining	1,190,468	1,080,399	976,751
Independent power production	250,602	184,127	79,373
Other	17,335	17,007	15,152
Less accumulated depreciation, depletion and amortization	1,358,723	1,187,105	1,026,932
Net property, plant and equipment	$2,572,705	$2,396,933	$2,107,372

* *Includes allocations of common utility property.*

** *Includes assets not directly assignable to a business (i.e., cash and cash equivalents, certain accounts receivable and other miscellaneous current and deferred assets).*

Excluding the asset impairments at the pipeline and energy services segment of $5.3 million (after tax), 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, independent power production, and other are all from nonregulated operations. Capital expenditures for 2004, 2003 and 2002, related to acquisitions, in the preceding table included the following noncash transactions: issuance of the Company's equity securities of $33.1 million, $42.4 million and $47.2 million in 2004, 2003 and 2002, respectively.

NOTE 14 – ACQUISITIONS

In 2004, the Company acquired a number of businesses, none of which was individually material, including construction materials and mining businesses in Hawaii, Idaho, Iowa and Minnesota and an independent power production operating and development company in Colorado. The total purchase consideration for these businesses and adjustments with respect to certain other acquisitions acquired prior to 2004, consisting of the Company's common stock and cash, was $70.3 million.

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, consisting of 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 April 2000, Fidelity 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 the Seller's Option Interest from Preston for an amount as specified in the agreement. In July 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 2004. 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 15 – 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. As discussed in Note 1, the Company recognized the effects of the 2003 Medicare Act during the second quarter of 2004. The net periodic benefit cost for 2004 reflects the effects of the 2003 Medicare Act. 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	
	2004	2003	**2004**	2003
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$261,335**	$224,766	**$ 88,381**	$ 74,917
Service cost	**7,667**	5,897	**1,826**	1,857
Interest cost	**15,903**	15,211	**4,312**	5,281
Plan participants' contributions	**–**	–	**1,133**	977
Amendments	**–**	210	**(773)**	754
Actuarial (gain) loss	**12,240**	27,701	**(14,951)**	10,338
Benefits paid	**(12,389)**	(12,450)	**(4,437)**	(5,743)
Benefit obligation at end of year	**284,756**	261,335	**75,491**	88,381
Change in plan assets:				
Fair value of plan assets at beginning of year	**223,043**	189,143	**47,234**	40,889
Actual gain on plan assets	**27,264**	43,087	**2,920**	6,148
Employer contribution	**1,604**	3,263	**4,127**	4,963
Plan participants' contributions	**–**	–	**1,134**	977
Benefits paid	**(12,389)**	(12,450)	**(4,437)**	(5,743)
Fair value of plan assets at end of year	**239,522**	223,043	**50,978**	47,234
Funded status – under	**(45,234)**	(38,292)	**(24,513)**	(41,147)
Unrecognized actuarial (gain) loss	**46,293**	41,422	**(1,832)**	11,862
Unrecognized prior service cost	**7,435**	8,556	**–**	706
Unrecognized net transition obligation (asset)	**(47)**	(297)	**16,999**	19,362
Prepaid (accrued) benefit cost	**$ 8,447**	$ 11,389	**$ (9,346)**	$ (9,217)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	**$ 19,020**	$ 19,671	**$ 572**	$ 614
Accrued benefit liability	**(10,573)**	(8,282)	**(9,918)**	(9,831)
Net amount recognized	**$ 8,447**	$ 11,389	**$ (9,346)**	$ (9,217)

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 $227.3 million and $212.0 million at December 31, 2004 and 2003, 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, 2004 and 2003, were as follows:

	2004	2003
	(In thousands)	
Projected benefit obligation	**$174,983**	$38,845
Accumulated benefit obligation	**$136,012**	$28,840
Fair value of plan assets	**$132,280**	$24,508

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,	**2004**	2003	2002	**2004**	2003	2002
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	**$ 7,667**	$ 5,897	$ 5,135	**$ 1,826**	$ 1,857	$ 1,460
Interest cost	**15,903**	15,211	14,877	**4,312**	5,281	4,915
Expected return on assets	**(20,375)**	(20,730)	(21,110)	**(3,943)**	(3,933)	(3,843)
Amortization of prior service cost	**1,121**	1,156	1,148	**144**	48	–
Recognized net actuarial (gain) loss	**480**	(417)	(1,855)	**(233)**	(255)	(566)
Amortization of net transition obligation (asset)	**(250)**	(950)	(947)	**2,151**	2,151	2,151
Net periodic benefit cost (income)	**4,546**	167	(2,752)	**4,257**	5,149	4,117
Less amount capitalized	**409**	14	(352)	**440**	601	404
Net periodic benefit cost (income)	**$ 4,137**	$ 153	$ (2,400)	**$ 3,817**	$ 4,548	$ 3,713

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

	Pension Benefits		Other Postretirement Benefits	
	2004	2003	**2004**	2003
Discount rate	**5.75%**	6.00%	**5.75%**	6.00%
Rate of compensation increase	**4.70%**	4.70%	**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	
	2004	2003	**2004**	2003
Discount rate	**6.00%**	6.75%	**6.00%**	6.75%
Expected return on plan assets	**8.50%**	8.50%	**7.50%**	7.50%
Rate of compensation increase	**4.70%**	4.50%	**4.50%**	4.50%

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:

	2004	2003
Health care trend rate assumed for next year	**6.0%–9.5%**	6.0%–9.5%
Health care cost trend rate – ultimate	**5.0%–6.0%**	5.0%–6.0%
Year in which ultimate trend rate achieved	**1999–2013**	1999–2012

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, 2004:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 218	$ (872)
Effect on postretirement benefit obligation	$3,176	$(8,489)

The Company's defined benefit pension plans' asset allocation at December 31, 2004 and 2003, and weighted average targeted asset allocations at December 31, 2004, were as follows:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	**2004**	2003	**2004**
Equity securities	**74%**	72%	**70%**
Fixed income securities	**24**	25	**30***
Other	**2**	3	**–**
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.

The Company's other postretirement benefit plans' asset allocation at December 31, 2004 and 2003, and weighted average targeted asset allocation at December 31, 2004, were as follows:

	Percentage of Plan Assets		Weighted Average Targeted Asset Allocation Percentage
Asset Category	**2004**	2003	**2004**
Equity securities	**70%**	66%	**70%**
Fixed income securities	**28**	30	**30***
Other	**2**	4	**–**
Total	**100%**	100%	**100%**

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

The Company expects to contribute approximately $900,000 to its defined benefit pension plans and approximately $3.8 million to its postretirement benefit plans in 2005.

The following benefit payments, which reflect future service, as appropriate, are expected to be paid:

Years	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2005	$12,403	$ 5,908
2006	12,726	5,666
2007	13,248	5,941
2008	13,830	6,204
2009	14,720	6,493
2010–2014	89,922	38,302

The following Medicare Part D subsidies are expected: none in 2005; $436,000 in 2006; $439,000 in 2007; $440,000 in 2008; $438,000 in 2009 and $2.2 million during the years 2010 through 2014.

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 $28.2 million, $27.2 million and $27.8 million in 2004, 2003 and 2002, respectively.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has an unfunded, nonqualified benefit plan for executive officers and certain key management employees that generally provides for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. Investments at December 31, 2004, consisted of cash equivalents and life insurance carried on plan participants, which is payable to the Company upon the employee's death. The Company's net periodic benefit cost for this plan was $7.5 million, $5.3 million and $5.1 million in 2004, 2003 and 2002, respectively. The total projected obligation for this plan was $65.3 million and $51.1 million at December 31, 2004 and 2003, respectively. The accumulated benefit obligation for this plan was $52.3 million and $40.7 million at December 31, 2004 and 2003, respectively. The additional minimum liability relating to this plan was $14.3 million and $8.2 million at December 31, 2004 and 2003, respectively. The Company has a related intangible asset recognized as of December 31, 2004 and 2003, of $851,000 and $1.0 million, respectively. A discount rate of 5.75 percent and 6.0 percent at December 31, 2004 and 2003, respectively, and a rate of compensation increase of 4.75 percent at both December 31, 2004 and 2003, were used to determine benefit obligations.

A discount rate of 6.00 percent and 6.75 percent at December 31, 2004 and 2003, respectively, and a rate of compensation increase of 4.75 percent and 4.50 percent at December 31, 2004 and 2003, respectively, were used to determine net periodic benefit cost. The increase in minimum liability included in other comprehensive income was $3.8 million in 2004 and $2.6 million in 2003.

The amount of benefit payments for the unfunded, nonqualified benefit plan, as appropriate, are expected to aggregate $2.5 million in 2005; $2.6 million in 2006; $3.1 million in 2007; $3.2 million in 2008; $3.3 million in 2009 and $20.0 million for the years 2010 through 2014.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $13.8 million in 2004, $9.8 million in 2003 and $9.6 million in 2002. The costs incurred in each year reflect additional participants as a result of business acquisitions.

NOTE 16 – 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:

	2004	2003
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 52,157	$ 52,154
Less accumulated depreciation	36,488	34,993
	$ 15,669	$ 17,161
Coyote Station:		
Utility plant in service	$124,388	$124,086
Less accumulated depreciation	74,671	72,850
	$ 49,717	$ 51,236

NOTE 17 – REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

On September 7, 2004, Great Plains filed an application with the MPUC for a natural gas rate increase. Great Plains had requested a total of $1.4 million annually or 4.0 percent above current rates. Great Plains also requested an interim increase of $1.4 million annually. On November 23, 2004, the MPUC issued an Order setting interim rates of $1.4 million annually effective with service rendered on or after January 10, 2005, subject to refund. A final order from the MPUC is expected in late 2005.

On June 7, 2004, Montana-Dakota filed an application with the SDPUC for a natural gas rate increase for the Black Hills service area. Montana-Dakota requested a total of $1.3 million annually or 2.2 percent above current rates. On November 15, 2004, Montana-Dakota and the SDPUC Staff filed a Settlement Stipulation with the SDPUC agreeing to an increase of $670,000 annually, or 1.4 percent. On November 30, 2004, the SDPUC approved the Settlement Stipulation effective with service rendered on or after December 1, 2004.

On April 1, 2004, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase. Montana-Dakota requested a total of $1.5 million annually or 1.8 percent above current rates. On January 14, 2005, Montana-Dakota and the Montana Consumer Counsel filed a Stipulation with the MTPSC agreeing to an increase of $125,000 annually to be effective with service rendered on or after February 1, 2005. On January 25, 2005, the MTPSC passed a Motion approving the Stipulation.

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 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. In July 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. In August 2003, Williston Basin requested 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 May 11, 2004, the FERC issued an Order on Rehearing. The Order on Rehearing denied rehearing on all of the issues addressed by Williston Basin in its August 2003 request for rehearing except for the issue of the proper rate to utilize for transmission system negative salvage expenses. In addition, the FERC remanded the issues regarding certain service and annual demand quantity restrictions to an ALJ for resolution. On June 14, 2004, Williston Basin requested clarification of a few of the issues addressed in the Order on Rehearing including determinations associated with cost of service and cost allocation, as discussed in the FERC's Order on Rehearing. On June 14, 2004, Williston Basin also made its filing to comply with the requirements of the various FERC orders in this proceeding. Williston Basin is awaiting a decision from the FERC on Williston Basin's compliance filing and clarification request but is unable to predict the timing of the FERC's decision. Williston Basin participated in a hearing before the ALJ in early January 2005, regarding the matters remanded to the ALJ by the FERC in its Order on Rehearing and an order on these matters is expected in 2005.

A liability has 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 the liability is adequate based on its assessment of the ultimate outcome of the proceeding.

NOTE 18 – 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, Grynberg filed suit under the Federal False Claims Act 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.

On June 4, 2004, following preliminary discovery, Williston Basin and Montana-Dakota joined with other defendants and filed a Motion to Dismiss on the grounds that the information upon which Grynberg based his complaint was publicly disclosed prior to the filing of his complaint and further, that he is not the original source of such information. The Motion to Dismiss is additionally based on the grounds that Grynberg disclosed the filing of the complaint prior to the entry of a court order allowing such disclosure and that Grynberg failed to provide adequate information to the government prior to filing suit.

In the event the Motion to Dismiss is not granted, it is expected that further discovery will follow. Williston Basin and Montana-Dakota believe Grynberg will not prevail in the suit or recover damages from Williston Basin and/or Montana-Dakota because insufficient facts exist to support the allegations. Williston Basin and Montana-Dakota believe Grynberg's claims are without merit and intend to vigorously contest this suit.

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.

Fidelity has been named as a defendant in, and/or certain of its operations are or have been the subject of, more than a dozen 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 November 2004 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. Portions of 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, the National Environmental Policy Act, the Federal Land Management Policy Act, the National Historic Preservation Act and the Montana Environmental Policy Act. The cases involving alleged violations of the Federal Clean Water Act have been resolved without a finding that Fidelity is in violation of the Federal Clean Water Act. There presently are no claims pending for penalties, fines or damages under the Federal Clean Water Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural requirements and the lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity is unable to quantify the damages sought in any of these cases, and will be unable to do so until after completion of discovery in these separate cases. 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 Health Department in September 2003 that the North Dakota Health 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 North Dakota Health 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 in October 2003, in the Burleigh County District Court in Bismarck, North Dakota. Proceedings have been stayed pending discussions with the EPA, the North Dakota Health Department and the other electric generators.

In a related matter, the state of North Dakota and the EPA entered into a MOU on February 24, 2004, establishing the principles to be used by the state of North Dakota in completing dispersion modeling of air quality in Theodore Roosevelt National Park and other "Class I" areas in North Dakota and Montana. In April 2004, the Dakota Resource Council filed a petition for review of the MOU with the United States Eighth Circuit Court of Appeals. The petition was dismissed, without prejudice, in June 2004 upon stipulation of the EPA, the Dakota Resource Council and the state of North Dakota. The Company cannot predict the outcome of the North Dakota Health 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, MBI 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 DEQ are being recorded, and initially paid, through an administrative consent order by the LWG, a group of 10 entities, which 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.

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, 2004, were $14.7 million in 2005, $10.5 million in 2006, $6.6 million in 2007, $5.1 million in 2008, $3.5 million in 2009 and $25.2 million thereafter. Rent expense was $30.6 million, $27.2 million and $26.9 million for the years ended December 31, 2004, 2003 and 2002, 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 20 years. The commitments under these contracts as of December 31, 2004, were $223.6 million in 2005, $105.7 million in 2006, $65.4 million in 2007, $50.5 million in 2008, $46.9 million in 2009 and $236.4 million thereafter. Amounts purchased under various commitments for the years ended December 31, 2004, 2003 and 2002, were approximately $318.3 million, $204.6 million and $152.1 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

In addition to the above obligations, the Company has certain purchase obligations for natural gas connected to its gathering system. These purchases and the resale of the natural gas are at market-based prices. These obligations continue as long as natural gas is produced. However, if the purchase and resale of natural gas become uneconomical, the purchase commitments can be canceled by the Company with 60 days notice. These purchase obligations are currently estimated at approximately $10 million annually.

Guarantees

Centennial has unconditionally guaranteed a portion of certain bank borrowings of MPX in connection with the Company's equity method investment in the Termoceara Generating Facility, 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, 2004, the aggregate amount of borrowings outstanding subject to these guarantees was $34.9 million and the scheduled repayment of these borrowings is $11.0 million in 2005, $10.7 million in 2006 and 2007 and $2.5 million in 2008. The individual investor (who through EBX owns 51 percent of MPX) has also guaranteed these loans. In the event MPX defaults under its obligation, Centennial and the individual investor would be required to make payments under their guarantees, which are joint and several obligations. 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 has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. Fidelity's obligations at December 31, 2004, were $4.9 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, 2004, expire in 2005; however, Fidelity 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, 2004, the amount outstanding was reflected on the Consolidated Balance Sheets. In the event Fidelity 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. These guarantees are related to natural gas transportation and sales agreements, electric power supply agreements, insurance policies and certain other guarantees. At December 31, 2004, the fixed maximum amounts guaranteed under these agreements aggregated $88.8 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $40.1 million in 2005; $4.7 million in 2006; $2.1 million in 2007; $300,000 in 2008; $900,000 in 2009; $22.0 million in 2010; $12.0 million in 2012; $2.2 million in 2028; $500,000, which is subject to expiration 30 days after the receipt of written notice and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $561,000 and was reflected on the Consolidated Balance Sheets at December 31, 2004. 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, 2004, 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 $1.7 million, which was not reflected on the Consolidated Balance Sheet at December 31, 2004, because these intercompany transactions are eliminated in consolidation.

In addition, Centennial has issued guarantees to third parties related to the Company's routine purchase of maintenance items 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 Sheet at December 31, 2004.

As of December 31, 2004, Centennial was contingently liable for the performance of certain of its subsidiaries under approximately $375 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 is 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.

NOTE 19 – RELATED PARTY TRANSACTIONS

In 2004, Bitter Creek entered into two natural gas gathering agreements with Nance Petroleum Corporation (Nance Petroleum), a wholly owned subsidiary of St. Mary Land & Exploration Company (St. Mary). Robert L. Nance, an executive officer and shareholder of St. Mary, is also a member of the Board of Directors of the Company. The natural gas gathering agreements with Nance Petroleum were effective upon completion of certain high and low pressure gathering facilities, which occurred in mid-December 2004. Bitter Creek's capital expenditures related to the completion of the gathering lines and the expansion of its gathering facilities to accommodate the natural gas gathering agreements were $7.6 million in 2004 and are estimated for the next three years to be $2.5 million in 2005, $2.2 million in 2006 and $3.3 million in 2007. The natural gas gathering agreements are each for a term of 15 years and month-to-month thereafter. Bitter Creek's revenues from these contracts were $37,000 in 2004 and estimated revenues from these contracts for the next three years are $1.9 million in 2005, $3.8 million in 2006 and $5.8 million in 2007. The amount due from Nance Petroleum at December 31, 2004, was $37,000.

SUPPLEMENTARY FINANCIAL INFORMATION

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2004 and 2003:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2004				
Operating revenues	$515,459	$653,301	$804,598	$745,899
Operating expenses	471,436	568,570	690,022	668,511
Operating income	44,023	84,731	114,576	77,388
Net income	23,580	58,630	71,719	53,138
Earnings per common share:				
Basic	.20	.50	.61	.45
Diluted	.20	.50	.60	.45
Weighted average common shares outstanding:				
Basic	114,658	116,559	117,109	117,582
Diluted	115,709	117,567	118,278	118,596
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

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:

	2004	2003	2002
		(In thousands)	
Subject to amortization	**$904,620**	$758,500	$603,151
Not subject to amortization	**68,984**	104,339	145,692
Total capitalized costs	**973,604**	862,839	748,843
Less accumulated depreciation, depletion and amortization	**373,932**	305,349	239,964
Net capitalized costs	**$599,672**	$557,490	$508,879

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

Years ended December 31,	2004*	2003*	2002
		(In thousands)	
Acquisitions	**$ 11,219**	$ 3,027	$ 31,439
Exploration	**21,781**	19,193	5,325
Development**	**77,940**	77,583	94,943
Total capital expenditures	**$110,940**	$99,803	$131,707

** Excludes net 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 8, of $100,000 and $14.7 million for the years ended December 31, 2004 and 2003, respectively.*

*** Includes expenditures for proved undeveloped reserves of $30.3 million, $23.3 million and $10.1 million for the years ended December 31, 2004, 2003 and 2002, 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,	2004	2003	2002*
		(In thousands)	
Revenues:			
Sales to affiliates	**$190,354**	$124,077	$ 55,437
Sales to external customers	**149,660**	140,034	145,170
Production costs	**67,125**	67,292	52,520
Depreciation, depletion and amortization**	**69,946**	60,072	48,064
Pretax income	**202,943**	136,747	100,023
Income tax expense	**73,137**	51,925	36,886
Results of operations for producing activities before cumulative effect of accounting change	**129,806**	84,822	63,137
Cumulative effect of accounting change	**–**	(7,740)	–
Results of operations for producing activities	**$129,806**	$ 77,082	$ 63,137

** Includes the compromise agreement as discussed in Note 18.*

*** Includes $1.4 million of accretion of discount for asset retirement obligations for each of the years ended December 31, 2004 and 2003, in accordance with SFAS No. 143, as discussed in Note 8.*

The following table summarizes the Company's estimated quantities of proved natural gas and oil reserves at December 31, 2004, 2003 and 2002, 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.

	2004		2003		2002	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
			(In thousands of Mcf/barrels)			
Proved developed and undeveloped reserves:						
Balance at beginning of year	**411,700**	**18,900**	372,500	17,500	324,100	17,500
Production	**(59,700)**	**(1,800)**	(54,700)	(1,900)	(48,200)	(2,000)
Extensions and discoveries	**100,700**	**500**	113,300	3,300	80,100	2,200
Purchases of proved reserves	**100**	**–**	900	–	1,200	100
Sales of reserves in place	**–**	**–**	–	(100)	(4,400)	(300)
Revisions of previous estimates	**400**	**(500)**	(20,300)	100	19,700	–
Balance at end of year	**453,200**	**17,100**	411,700	18,900	372,500	17,500

Proved developed reserves:		
January 1, 2002	291,300	17,100
December 31, 2002	331,300	14,800
December 31, 2003	342,800	15,000
December 31, 2004	**376,400**	**16,400**

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:

	2004	2003	2002
		(In thousands)	
Future cash inflows	**$2,848,800**	$2,547,400	$1,726,000
Future production costs	**803,600**	651,300	513,200
Future development costs	**62,800**	67,100	61,200
Future net cash flows before income taxes	**1,982,400**	1,829,000	1,151,600
Future income tax expense	**645,300**	601,000	324,000
Future net cash flows	**1,337,100**	1,228,000	827,600
10% annual discount for estimated timing of cash flows	**515,600**	491,200	321,300
Discounted future net cash flows relating to proved natural gas and oil reserves	**$ 821,500**	$ 736,800	$ 506,300

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

	2004	2003	2002
		(In thousands)	
Beginning of year	**$ 736,800**	$ 506,300	$ 262,000
Net revenues from production	**(291,600)**	(220,000)	(112,900)
Change in net realization	**32,800**	318,600	296,100
Extensions, discoveries and improved recovery, net of future production-related costs	**240,200**	245,800	117,000
Purchases of proved reserves	**300**	2,800	3,700
Sales of reserves in place	**–**	(600)	(8,900)
Changes in estimated future development costs	**(5,300)**	(4,000)	(1,100)
Development costs incurred during the current year	**39,800**	35,300	19,400
Accretion of discount	**97,100**	62,400	27,300
Net change in income taxes	**(36,400)**	(172,000)	(124,700)
Revisions of previous estimates	**9,600**	(35,500)	30,000
Other	**(1,800)**	(2,300)	(1,600)
Net change	**84,700**	230,500	244,300
End of year	**$ 821,500**	$ 736,800	$ 506,300

The estimated discounted future cash inflows from estimated future production of proved reserves were computed using year-end natural gas 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 as of December 31, 2004, are $37.9 million in 2005, $7.6 million in 2006 and none in 2007. 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.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

The following information includes the evaluation of disclosure controls and procedures by the Company's chief executive officer and the chief financial officer, along with any significant changes in internal controls of the Company.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act). These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files under the Exchange Act is recorded, processed, summarized and reported within required time periods. The Company's chief executive officer and chief financial officer have evaluated the effectiveness of the Company's disclosure controls and procedures and they have concluded that, as of the end of the period covered by this report, such controls and procedures were effective.

CHANGES IN INTERNAL CONTROLS

The Company maintains a system of internal accounting controls that is designed to provide reasonable assurance that the Company's transactions are properly authorized, the Company's assets are safeguarded against unauthorized or improper use, and the Company's transactions are properly recorded and reported to permit preparation of the Company's financial statements in conformity with generally accepted accounting principles in the United States of America. There were no changes in the Company's internal control over financial reporting that occurred during the period covered by this report that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The information required by this item is included in this Form 10-K at Item 8 – Financial Statements and Supplementary Data – Management's Report on Internal Control over Financial Reporting.

ATTESTATION REPORT OF THE REGISTERED PUBLIC ACCOUNTING FIRM

The information required by this item is included in this Form 10-K at Item 8 – Financial Statements and Supplementary Data – Report of Independent Registered Public Accounting Firm.

ITEM 9B. OTHER INFORMATION

None.

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS OF THE REGISTRANT

The information required by this item is included under the captions "Election of Directors," "Continuing Incumbent Directors," "Information Concerning Executive Officers," "Section 16 (a) Beneficial Ownership Reporting Compliance," "Board and Board Committees" and "Nominating and Governance Committee" in the Company's 2005 Proxy Statement (Proxy Statement), which is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is included under the captions "Directors' Compensation" and "Executive Compensation" of the Proxy Statement, which is incorporated herein by reference with the exception of the compensation committee report on executive compensation and the performance graph.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required by this item is included under the captions "Security Ownership" and "Re-approval of 1997 Executive LTIP Performance Goals" of the Proxy Statement, which is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

None.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is included under the caption "Accounting and Auditing Matters" of the Proxy Statement, which is incorporated herein by reference.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) FINANCIAL STATEMENTS, FINANCIAL STATEMENT SCHEDULES AND EXHIBITS

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

The following consolidated financial statements required under this item are included under Item 8 – Financial Statements and Supplementary Data.

2. Financial Statement Schedules

MDU Resources Group, Inc.
Schedule II – Consolidated Valuation and Qualifying Accounts
Years Ended December 31, 2004, 2003 and 2002

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other*	Deductions**	Balance at End of Year
			(In thousands)		
Allowance for doubtful accounts:					
2004	**$8,146**	**$2,663**	**$ 703**	**$4,711**	**$6,801**
2003	8,237	3,185	1,123	4,399	8,146
2002	5,773	8,192	1,164	6,892	8,237

* *Allowance for doubtful accounts for companies acquired and recoveries.*
** *Uncollectible accounts written off.*

All other schedules are omitted because of the absence of the conditions under which they are required, or because the information required is included in the Company's Consolidated Financial Statements and Notes thereto.

3. Exhibits

3(a) Restated Certificate of Incorporation of the Company, as amended, filed as Exhibit 3(a) to Form S-3 on June 13, 2003, in Registration No. 333-104150*

3(b) By-laws of the Company, as amended, filed as Exhibit 3.3 to Form 8-A/A on March 10, 2003, in File No. 1-3480*

3(c) Certificate of Designations of Series B Preference Stock of the Company, as amended, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

4(a) Indenture of Mortgage, dated as of May 1, 1939, as restated in the Forty-Fifth Supplemental Indenture, dated as of April 21, 1992, and the Forty-Sixth through Forty-Ninth Supplements thereto between the Company and the New York Trust Company (The Bank of New York, successor Corporate Trustee) and A. C. Downing (Douglas J. MacInnes, successor Co-Trustee), filed as Exhibit 4(a) in Registration No. 33-66682; and Exhibits 4(e), 4(f) and 4(g) in Registration No. 33-53896; and Exhibit 4(c)(i) in Registration No. 333-49472*

4(b) Fiftieth Supplemental Indenture, dated as of December 15, 2003, filed as Exhibit 4(e) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

4(c) Rights agreement, dated as of November 12, 1998, between the Company and Wells Fargo Bank Minnesota, N.A. (formerly known as Norwest Bank Minnesota, N.A.), Rights Agent, filed as Exhibit 4.1 to Form 8-A on November 12, 1998, in File No. 1-3480*

4(d) Indenture, dated as of December 15, 2003, between the Company and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

4(e) Certificate of Adjustment to Purchase Price and Redemption Price, as amended and restated, pursuant to the Rights Agreement, dated as of November 12, 1998, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2003, in File No. 1-3480*

+10(a) MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2004, in File No. 1-3480*

+10(b) 1992 Key Employee Stock Option Plan, as amended, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2002, in File No. 1-3480*

+10(c) Supplemental Income Security Plan, as amended, filed as Exhibit 10(c) to Form 10-K for the year ended December 31, 2002, in File No. 1-3480*

+10(d) Directors' Compensation Policy, as amended, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2003, in File No. 1-3480*

+10(e) Deferred Compensation Plan for Directors, as amended, filed as Exhibit 10(e) to Form 10-K for the year ended December 31, 2002, in File No. 1-3480*

+10(f) Non-Employee Director Stock Compensation Plan, as amended, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2003, in File No. 1-3480*

+10(g) 1997 Non-Employee Director Long-Term Incentive Plan, as amended, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2000, in File No. 1-3480*

+10(h) 1997 Executive Long-Term Incentive Plan, as amended, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2001, in File No. 1-3480*

+10(i) Montana-Dakota Executive Incentive Compensation Plan, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2004, in File No. 1-3480*

+10(j) Performance Share Award Agreement, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2004, in File No. 1-3480*

+10(k) Change of Control Employment Agreement between the Company and John K. Castleberry, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

+10(l) Change of Control Employment Agreement between the Company and Cathleen M. Christopherson, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

+10(m) Change of Control Employment Agreement between the Company and Paul Gatzemeier, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2004, in File No. 1-3480*

+10(n) Change of Control Employment Agreement between the Company and Mary B. Hager, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2004, in File No. 1-3480*

+10(o) Change of Control Employment Agreement between the Company and Terry D. Hildestad, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

+10(p) Change of Control Employment Agreement between the Company and Bruce T. Imsdahl, filed as Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2004, in File No. 1-3480*

+10(q) Change of Control Employment Agreement between the Company and Vernon A. Raile, filed as Exhibit 10(f) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

+10(r) Change of Control Employment Agreement between the Company and Cindy C. Redding, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2004, in File No. 1-3480*

+10(s) Change of Control Employment Agreement between the Company and Warren L. Robinson, filed as Exhibit 10(g) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

+10(t) Change of Control Employment Agreement between the Company and Paul K. Sandness, filed as Exhibit 10(e) to Form 10-Q for the quarter ended June 30, 2004, in File No. 1-3480*

+10(u) Change of Control Employment Agreement between the Company and William E. Schneider, filed as Exhibit 10(h) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

+10(v) Change of Control Employment Agreement between the Company and Daryl A. Splichal, filed as Exhibit 10(f) to Form 10-Q for the quarter ended June 30, 2004, in File No. 1-3480*

+10(w) Change of Control Employment Agreement between the Company and Martin A. White, filed as Exhibit 10(j) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

+10(x) Change of Control Employment Agreement between the Company and Floyd E. Wilson, filed as Exhibit 10(g) to Form 10-Q for the quarter ended June 30, 2004, in File No. 1-3480*

+10(y) Change of Control Employment Agreement between the Company and Robert E. Wood, filed as Exhibit 10(k) to Form 10-Q for the quarter ended September 30, 2002, in File No. 1-3480*

+10(z) Agreement on Retirement between the Company and Lester H. Loble, II, filed as Exhibit 10(v) to Form 10-K for the year ended December 31, 2003, in File No. 1-3480*

+10(aa) Agreement on Retirement between the Company and Ronald D. Tipton, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2004, in File No. 1-3480*

+10(ab) Separation Agreement and Release between the Company and Douglas C. Kane, filed as Exhibit 10(t) to Form 10-K for the year ended December 31, 2002, in File No. 1-3480*

+10(ac) 1998 Option Award Program, filed as Exhibit 10(u) to Form 10-K for the year ended December 31, 2002, in File No. 1-3480*

+10(ad) Group Genius Innovation Plan, filed as Exhibit 10(v) to Form 10-K for the year ended December 31, 2002, in File No. 1-3480*

+10(ae) The Wagner-Smith Company Deferred Compensation Plan, filed as Exhibit 10(w) to Form 10-K for the year ended December 31, 2003, in File No. 1-3480*

+10(af) Wagner-Smith Equipment Co. Deferred Compensation Plan, filed as Exhibit 10(x) to Form 10-K for the year ended December 31, 2003, in File No. 1-3480*

+10(ag) The Capital Electric Construction Company, Inc. Deferred Compensation Plan, filed as Exhibit 10(y) to Form 10-K for the year ended December 31, 2003, in File No. 1-3480*

+10(ah) The Capital Electric Line Builders, Inc. Deferred Compensation Plan, filed as Exhibit 10(z) to Form 10-K for the year ended December 31, 2003, in File No. 1-3480*

+10(ai) The Bauerly Brothers, Inc. Deferred Compensation Plan, filed as Exhibit 10(aa) to Form 10-K for the year ended December 31, 2003, in File No. 1-3480*

+10(aj) The Oregon Electric Construction, Inc. Deferred Compensation Plan, filed as Exhibit 10(ab) to Form 10-K for the year ended December 31, 2003, in File No. 1-3480*

12 Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**

21 Subsidiaries of MDU Resources Group, Inc.**

23 Consent of Independent Registered Public Accounting Firm**

31(a) Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

31(b) Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

32 Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**

** Incorporated herein by reference as indicated.*

*** Filed herewith.*

+ Management contract, compensatory plan or arrangement required to be filed as an exhibit to this form pursuant to Item 15(c) of this report.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

MDU RESOURCES GROUP, INC.

Date: February 23, 2005

By: /s/ Martin A. White

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

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

Signature	Title	Date
/s/ Martin A. White Martin A. White (Chairman of the Board, President and Chief Executive Officer)	Chief Executive Officer and Director	February 23, 2005
/s/ Warren L. Robinson Warren L. Robinson (Executive Vice President and Chief Financial Officer)	Chief Financial Officer	February 23, 2005
/s/ Vernon A. Raile Vernon A. Raile (Senior Vice President and Chief Accounting Officer)	Chief Accounting Officer	February 23, 2005
/s/ Harry J. Pearce Harry J. Pearce	Lead Director	February 23, 2005
/s/ Bruce R. Albertson Bruce R. Albertson	Director	February 23, 2005
/s/ Thomas Everist Thomas Everist	Director	February 23, 2005
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 23, 2005
/s/ Patricia L. Moss Patricia L. Moss	Director	February 23, 2005
/s/ Robert L. Nance Robert L. Nance	Director	February 23, 2005
/s/ John L. Olson John L. Olson	Director	February 23, 2005
/s/ Sister Thomas Welder Sister Thomas Welder	Director	February 23, 2005
/s/ John K. Wilson John K. Wilson	Director	February 23, 2005

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.

Coalbed natural gas Natural gas produced from coal deposits.

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

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

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

Electric sales for resale Electric energy sales to customers who, in turn, resell it to their customers.

Environmental Protection Agency (EPA) Federal agency that develops and enforces regulations under existing environmental laws.

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

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

Gathering Pipelines and related facilities used to bring natural gas from the well to a central distribution point.

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, electric lines, natural gas pipelines 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 Typically a depleted oil or natural gas field into which natural gas is injected and withdrawn as needed primarily to help meet winter heating demand.

Open access A regulatory mandate that allows others to use a pipeline's transmission facilities to move natural gas from one point to another on a nondiscriminatory basis for a cost-based fee.

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.

Sarbanes-Oxley Act of 2002 (SOX) Corporate-reform legislation enacted by Congress designed to improve corporate governance.

Securities and Exchange Commission (SEC) Federal agency that regulates financial markets.

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.

Corporate Headquarters
MDU Resources Group, Inc.
Schuchart Building
Street Address: 918 E. Divide Ave.
Mailing Address: P.O. Box 5650
Bismarck, ND 58506-5650
Telephone: (800) 437-8000
www.mdu.com

Common Stock
MDU Resources' 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 2004 was 205,400 shares. The quarterly common stock prices for 2004 and 2003 are listed below:

	High	Low	Close
2004			
First Quarter	$24.35	$22.67	$23.49
Second Quarter	24.03	21.85	24.03
Third Quarter	26.43	23.72	26.33
Fourth Quarter	27.70	25.20	26.68
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

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

Dividend Reinvestment and Direct Stock Purchase Plan
The company's Dividend Reinvestment and Direct Stock Purchase Plan provides interested investors the opportunity to purchase shares of the company's common stock and to reinvest all or a percentage of their dividends without incurring brokerage commissions or service charges. For complete details, including an enrollment form, contact the stock transfer agent or the Investor Relations Department at MDU Resources. Plan information also is available on the Wells Fargo Shareowner Services Web site: www.wellsfargo.com/shareownerservices.

2005 Key Dividend Dates

	Ex-Dividend Date	Record Date	Payment Date
First Quarter	March 8	March 10	April 1
Second Quarter	June 7	June 9	July 1
Third Quarter	September 6	September 8	October 1
Fourth Quarter	December 6	December 8	January 1, 2006

Key dividend dates are subject to discretion of the Board of Directors.

Internet Account Access
Registered shareholders have electronic access to their accounts by visiting www.shareowneronline.com. Shareowner Online allows shareholders to view their account balance, dividend information, reinvestment details and more. Wells Fargo Bank, N.A., the transfer agent and registrar, maintains stockholder account access.

Investor Relations
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. Company information, including financial reports, is available 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 shareholders by brokers is listed in the broker's name, or "street name." Annual and quarterly reports, proxy material and dividend payments are sent to shareholders by their broker. Questions regarding mailings or dividend reinvestment should be directed to the broker.

Annual Meeting
Tuesday, April 26, 2005
11 a.m. CDT
Montana-Dakota Utilities Co. Service Center
909 Airport Road
Bismarck, North Dakota

Transfer Agent and Registrar for all Classes of Stock and Dividend Reinvestment Plan Agent
Wells Fargo Bank, N.A.
Stock Transfer Department
P.O. Box 64856
St. Paul, MN 55164-0856
Telephone: (651) 450-4064
Toll-Free Telephone: (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

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

The Object of your mission is to explore the Missouri river & such principal stream of it as by it's course and communication with the waters of the Pacific ocean... may offer the most direct & practicable water communication across this continent for the purpose of commerce.

— THOMAS JEFFERSON, 1803

MDU Resources Group, Inc.
Schuchart Building
918 E. Divide Ave.
P.O. Box 5650
Bismarck, ND 58506-5650
(800) 437-8000
(701) 222-7900
Trading Symbol: MDU
www.mdu.com