MDU RESOURCES GROUP INC
Form 10-K
February 21, 2007

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

FORM 10-K

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

For the fiscal year ended December 31, 2006

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

1200 West Century Avenue
P.O. Box 5650
Bismarck, North Dakota 58506-5650
(Address of principal executive offices)
(Zip Code)

(701) 530-1000
(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

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

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

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

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act. Yes o No x.

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 o.

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. x

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of “accelerated filer and large accelerated filer” in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer x Accelerated filer o Non-accelerated filer o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o Nox.

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2006: $4,393,239,107.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 12, 2007: 181,147,966 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant’s 2007 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

CONTENTS

DEFINITIONS

The following abbreviations and acronyms used in this Form 10-K are defined below:

Abbreviation or Acronym	
2003 Medicare Act	Medicare Prescription Drug, Improvement and Modernization Act of 2003
AFUDC	Allowance for funds used during construction
ALJ	Administrative Law Judge
Alusa	Tecnica de Engenharia Electrica - Alusa
Anadarko	Anadarko Petroleum Corporation
APB	Accounting Principles Board
APB Opinion No. 25	Accounting for Stock-Based Compensation
Arch	Arch Coal Sales Company
Army Corps	U.S. Army Corps of Engineers
Badger Hills Project	Tongue River-Badger Hills Project
Bbl	Barrel
Bcf	Billion cubic feet
BER	Montana Board of Environmental Review
Big Stone Station	450-MW coal-fired electric generating facility located near Big Stone City, South Dakota (22.7 percent ownership)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
BLM	Bureau of Land Management
Brascan	Brascan Brasil Ltda.
Brazilian Transmission Lines	Company’s equity method investment in companies owning ECTE, ENTE and ERTE
Brush Generating Facility	213 MW of natural gas-fired electric generating facilities near Brush, Colorado
Btu	British thermal units
Carib Power	Carib Power Management LLC

Cascade	Cascade Natural Gas Corporation
CBNG	Coalbed natural gas
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a direct wholly owned subsidiary of Centennial Resources
CEMIG	Companhia Energética de Minas Gerais - CEMIG
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial International	Centennial Energy Resources International, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial Power	Centennial Power, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Clean Air Act	Federal Clean Air Act
Clean Water Act	Federal Clean Water Act
Colorado Federal District Court	U.S. District Court for the District of Colorado
Company	MDU Resources Group, Inc.
D.C. Appeals Court	U.S. Court of Appeals for the District of Columbia Circuit
dk	Decatherm
DRC	Dakota Resource Council
EBSR	Elk Basin Storage Reservoir, one of Williston Basin's natural gas storage reservoirs, which is located in Montana and Wyoming
ECTE	Empresa Catarinense de Transmissão de Energia S.A.
EITF	Emerging Issues Task Force
EITF No. 00-21	Revenue Arrangements with Multiple Deliverables
EITF No. 04-6	Accounting for Stripping Costs in the Mining Industry
EITF No. 91-6	Revenue Recognition of Long-Term Power Sales Contracts
EIS	Environmental Impact Statement
ENTE	Empresa Norte de Transmissão de Energia S.A.
EPA	U.S. Environmental Protection Agency
ERTE	Empresa Regional de Transmissão de Energia S.A.
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
FIN	FASB Interpretation No.
FIN 47	Accounting for Conditional Asset Retirement Obligations - An Interpretation of FASB Statement No. 143
FIN 48	Accounting for Uncertainty in Income Taxes
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
Grynberg	Jack J. Grynberg
Hardin Generating Facility	

	116-MW coal-fired electric generating facility near Hardin, Montana
Hart-Scott-Rodino Act	Hart-Scott-Rodino Antitrust Improvements Act, as amended
Hartwell	Hartwell Energy Limited Partnership
Hartwell Generating Facility	310-MW natural gas-fired electric generating facility near Hartwell, Georgia (50 percent ownership)
Hobbs Power	Hobbs Power Funding, LLC, an indirect subsidiary of ArcLight Energy Partners Fund III, L.P.
Howell	Howell Petroleum Corporation, a wholly owned subsidiary of Anadarko
IBEW	International Brotherhood of Electrical Workers
Indenture	Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York as Trustee
Innovatum	Innovatum, Inc., a former indirect wholly owned subsidiary of WBI Holdings (the stock and a portion of Innovatum's assets were sold during the fourth quarter of 2006)
Item 8	Financial Statements and Supplementary Data
K-Plan	Company's 401(k) Retirement Plan
Kennecott	Kennecott Coal Sales Company
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
kW	Kilowatts
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a former direct wholly owned subsidiary of Centennial Power (member interests were sold in October 2006)
LWG	Lower Willamette Group
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels of oil or other liquid hydrocarbons
MBI	Morse Bros., Inc., an indirect wholly owned subsidiary of Knife River
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial International
MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
MMBtu	Million Btu
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana State Department of Environmental Quality
Montana Federal District Court	U.S. District Court for the District of Montana
Mortgage	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
MPX	MPX Termoceara Ltda. (49 percent ownership, sold in June 2005)
MTPSC	Montana Public Service Commission
MW	Megawatt
Nance Petroleum	Nance Petroleum Corporation, a wholly owned subsidiary of St. Mary
ND Health Department	North Dakota Department of Health
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
NHPA	National Historic Preservation Act
Ninth Circuit	U.S. Ninth Circuit Court of Appeals
NPRC	Northern Plains Resource Council
Oglethorpe	Oglethorpe Power Corporation
Order on Rehearing	Order on Rehearing and Compliance and Remanding Certain Issues for Hearing
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PPA	Power purchase and sale agreement
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2007 Proxy Statement
PSCo	Public Service Company of Colorado, a wholly owned subsidiary of Xcel Energy
RCRA	Resource Conservation and Recovery Act
SAFETEA-LU	Safe, Accountable, Flexible and Efficient Transportation Equity Act - A Legacy for Users
San Joaquin	San Joaquin Cogen, LLC, a direct wholly owned subsidiary of Centennial Power
San Joaquin Generating Facility	48-MW natural gas-fired electric generating facility near Lathrop, California
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEIS	Supplemental Environmental Impact Statement
SFAS	Statement of Financial Accounting Standards
SFAS No. 71	Accounting for the Effects of Certain Types of Regulation
SFAS No. 87	Employers' Accounting for Pensions
SFAS No. 109	Accounting for Income Taxes
SFAS No. 123	Accounting for Stock-Based Compensation
SFAS No. 123 (revised)	Share-Based Payment (revised 2004)
SFAS No. 142	Goodwill and Other Intangible Assets
SFAS No. 143	Accounting for Asset Retirement Obligations
SFAS No. 144	Accounting for the Impairment or Disposal of Long-Lived Assets
SFAS No. 148	Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of SFAS No. 123
SFAS No. 157	Fair Value Measurements
SFAS No. 158	Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans
Sheridan System	A separate electric system owned by Montana-Dakota
SIP	State Implementation Act

SMCRA	Surface Mining Control and Reclamation Act
St. Mary	St. Mary Land & Exploration Company
Stock Purchase Plan	Company’s Dividend Reinvestment and Direct Stock Purchase Plan
Termoceara Generating Facility	220-MW natural gas-fired electric generating facility in the Brazilian state of Ceara, owned and operated by MPX
Trinity Generating Facility	225-MW natural gas-fired electric generating facility in Trinidad and Tobago (49.99 percent ownership)
T&TEC	Trinidad and Tobago Electric Commission
TRWUA	Tongue River Water Users’ Association
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
Westmoreland	Westmoreland Coal Company
Williston Basin	Williston Basin Interstate Pipeline Company, an indirect wholly owned subsidiary of WBI Holdings
Wyoming Federal District Court	U.S. District Court for the District of Wyoming
WYPSC	Wyoming Public Service Commission

PART I

FORWARD-LOOKING STATEMENTS

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. 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, and 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 Item 7 - MD&A - Prospective Information.

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. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A - Risk Factors.

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 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

Montana-Dakota, through the electric and natural gas distribution segments, generates, transmits and distributes electricity and distributes natural gas in Montana, North Dakota, South Dakota and Wyoming. Great Plains distributes natural gas in western Minnesota and southeastern North Dakota. These operations also supply related value-added products and services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the natural gas and oil production segments), Knife River (construction materials and mining segment), MDU Construction Services (construction services segment), Centennial Resources (independent power production segment) and Centennial Capital (reflected in the Other category).

As of December 31, 2006, the Company had 11,526 employees with 161 employed at MDU Resources Group, Inc., 885 at Montana-Dakota, 35 at Great Plains, 539 at WBI Holdings, 5,032 at Knife River, 4,715 at MDU Construction Services and 159 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, 426 and 73 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2007, and March 31, 2008, for Montana-Dakota and Williston Basin, respectively.

Knife River has 43 labor contracts that represent approximately 1,000 of its construction materials employees. Knife River is in negotiations on nine of its labor contracts.

MDU Construction Services has 82 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 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 - Note 15 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 to 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 - Note 20. There are no pending 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 Exchange Act are available free of charge through the Company's Web site as soon as reasonably practicable after the Company has electronically filed such reports with, or furnished such reports to, the 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 119,000 residential, commercial, industrial and municipal customers located in 177 communities and adjacent rural areas as of December 31, 2006. 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 4,400 miles of transmission and distribution lines, respectively. Montana-Dakota has obtained and holds, or is in the process of renewing, 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, 2006, Montana-Dakota's net electric plant investment approximated $319.8 million.

Substantially all of Montana-Dakota's electric properties are subject to the lien of the Mortgage and to the junior lien of the Indenture.

The percentage of Montana-Dakota's 2006 retail electric utility operating revenues by jurisdiction is as follows: North Dakota - 60 percent; Montana - 22 percent; South Dakota - 7 percent; and Wyoming - 11 percent. Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters. Montana-Dakota participates in the Midwest ISO wholesale energy market.

The Midwest ISO is a regional transmission organization responsible for operational control of the transmission systems of its members. The Midwest ISO provides security center operations, tariff administration and operates a day-ahead and real-time energy market. As a member of Midwest ISO, Montana-Dakota's generation is sold into the Midwest ISO energy market and its energy needs are purchased from that market.

System Supply and System Demand Through an interconnected electric system, Montana-Dakota serves markets in portions of 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 electric generating stations, which have an aggregate turbine nameplate rating attributable to Montana-Dakota's interest of 436,055 kW and a total summer net capability of 478,270 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. In September 2005, Montana-Dakota entered into a contract for seasonal capacity from a neighboring utility, starting at 85 MW in 2007, increasing to 105 MW in 2011, with an option for capacity in 2012. Energy also will be purchased as needed from the Midwest ISO market.

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

Generating Station	Type	Nameplate Rating (kW)	Summer Capability (kW)	2006 Net Generation (kWh in thousands)

North Dakota:				
Coyote*	Steam	103,647	106,750	701,413
Heskett	Steam	86,000	102,870	444,266
Williston	Combustion Turbine	7,800	9,600	(66)**
South Dakota:				
Big Stone*	Steam	94,111	104,550	727,347
Montana:				
Lewis & Clark	Steam	44,000	52,300	336,936
Glendive	Combustion Turbine	77,347	79,400	6,514
Miles City	Combustion Turbine	23,150	22,800	1,649
		436,055	478,270	2,218,059

* Reflects Montana-Dakota's ownership interest.
** Station use, to meet MAPP’s 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. Contracts with Westmoreland for the Coyote, Heskett and Lewis & Clark stations expire in May 2016, April 2011 and December 2007, respectively. In July 2004, Montana-Dakota entered into separate three-year coal supply agreements with each of Kennecott and Arch to meet the majority of the Big Stone Station’s fuel requirements for the years 2005 to 2007 at contracted pricing. The Kennecott agreement provides for the purchase of 1.3 million tons of coal in 2007. The Arch agreement provides for the purchase of 500,000 tons of coal in 2007.

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 provides for the purchase of coal necessary to supply the coal requirements of Heskett Station at contracted pricing. Montana-Dakota estimates the coal requirement to be in the range of 500,000 to 600,000 tons per contract year. 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, 2004, through December 31, 2006, the average cost of coal purchased, including freight at Montana-Dakota's electric generating stations (including the Big Stone and Coyote stations) was as follows:

Years Ended December 31,		**2006**		2005		2004
Average cost of coal per million Btu	**$**	**1.26**	$	1.14	$	1.08
Average cost of coal per ton	**$**	**18.48**	$	17.01	$	15.96

The maximum electric peak demand experienced to date attributable to sales to retail customers on the interconnected system was 485,456 kW in July 2006. 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 2012 will approximate 1.2 percent annually.

Montana-Dakota expects that it has adequate capacity available through existing baseload generating stations, turbine peaking stations and firm contracts to meet the peak demand requirements of its customers through 2012. Future capacity that is needed to replace contracts and meet system growth requirements is expected to be met by constructing new generation resources or acquiring additional capacity through power contracts. For additional information regarding potential power generation projects, see Item 7 - MD&A - Prospective Information - Electric.

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

Through the 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 56,400 kW and occurred in July 2006.

In December 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 from January 1, 2007, to December 31, 2016. This contract also provides an option for Montana-Dakota to purchase
25 MW of an existing or future baseload coal-fired electric generating facility from Black Hills Power to serve the Sheridan load.

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.

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. An Electric Power Supply Cost Adjustment mechanism approved by the WYPSC in December 2006 will allow Montana-Dakota to timely reflect increases or decreases in fuel and purchased power costs related to the power supply contract with Black Hills Power mentioned above. In Montana, which in 2006 accounted for 22 percent of retail 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.

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. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. One permit was renewed in 2006. The next permit will expire in 2009. State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities on the Yellowstone and Missouri rivers. These permits also have five-year lives. 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 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 RCRA. Montana-Dakota routinely handles PCBs from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

On November 20, 2006, the Sierra Club sent a notice of intent to file a citizen suit in federal court under the Clean Air Act to the co-owners, including Montana-Dakota, of the Big Stone Station. For more information regarding this notice, see Item 8 - Note 20.

Montana-Dakota did not incur any material environmental expenditures in 2006. Expenditures are estimated to be $4.6 million, $16.3 million and $4.2 million in 2007, 2008 and 2009, respectively, to maintain environmental compliance as new emission controls are required. Projects will include sulfur-dioxide and mercury control equipment installation at the power plants. For matters involving Montana-Dakota and the ND Health Department, see Item 8 - Note 20.

NATURAL GAS DISTRIBUTION

General Montana-Dakota sells natural gas at retail, serving over 231,000 residential, commercial and industrial customers in 145 communities and adjacent rural areas as of December 31, 2006, 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 in 19 communities and adjacent rural areas as of December 31, 2006, 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 5,600 miles. Montana-Dakota and Great Plains have obtained and hold, or are in the process of renewing, 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, 2006, Montana-Dakota's and Great Plains' net natural gas distribution plant investment approximated $164.0 million.

Substantially all of Montana-Dakota's natural gas distribution properties are subject to the lien of the Mortgage and to the junior lien of the Indenture.

The percentage of Montana-Dakota's and Great Plains' 2006 natural gas utility operating revenues by jurisdiction is as follows: North Dakota - 39 percent; Minnesota - 11 percent; Montana - 24 percent; South Dakota - 20 percent; and Wyoming - 6 percent. 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 certain security issuances. The natural gas distribution operations of Great Plains are subject to regulation by the NDPSC and MNPUC regarding retail rates, service, accounting and certain security issuances.

During 2006, the Company entered into a definitive merger agreement to acquire Cascade. For more information regarding Cascade, see Item 8 - Note 22.

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 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 weather normalization 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:

Years Ended December 31,	**2006**	2005	2004
		(Mdk)	
Sales:			
Residential	**18,998**	20,086	20,303
Commercial	**13,830**	14,457	14,598
Industrial	**1,725**	1,688	1,706
Total	**34,553**	36,231	36,607
Transportation:			

Commercial	**1,579**	1,637	1,702
Industrial	**12,479**	12,928	12,154
Total	**14,058**	14,565	13,856
Total throughput	**48,611**	50,796	50,463
Degree days * (% of normal)	**86.7%**	90.9%	90.7%

* 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 also has contracted with Williston Basin and Great Plains has contracted with Northern Natural Gas Company to provide firm storage services that enable both divisions to meet winter peak requirements as well as allow them to better manage their 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 In September 2004, Great Plains filed an application with the MNPUC for a natural gas rate increase. For additional information regarding Great Plains' natural gas rate increase filing, see Item 8 - Note 19.

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 to 28 months from the time such costs are paid.

Montana-Dakota’s North Dakota, South Dakota-Black Hills and South Dakota-East River area natural gas tariffs contain a weather normalization mechanism applicable to firm customers that adjusts the distribution delivery charge revenues to reflect 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 2006 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations in relation to the natural gas distribution operations through 2009.

Montana-Dakota commenced the remediation of a historic manufactured gas plant located in Bismarck, North Dakota, in early 2007. Expenses related to this work are not expected to be material and are expected to be recovered through the regulatory process. In addition, Montana-Dakota has had an economic interest in five other historic manufactured gas plants within its service territory, none of which are currently being actively investigated, and for which any remediation expenses are not expected to be material.

CONSTRUCTION SERVICES

General MDU Construction Services specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling, external lighting and traffic signalization, and mechanical and fire protection services as well as the manufacture and distribution of specialty equipment. These services are provided to utilities and large manufacturing, commercial, government and institutional customers.

During 2006, the Company acquired a construction service business in Nevada. This acquisition was not material to the Company.

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

MDU Construction 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, 2006, MDU Construction Services owned or leased offices in 16 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops. At December 31, 2006, MDU Construction Services' net plant investment was approximately $45.8 million.

MDU Construction 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, 2006, was approximately $527 million compared to $403 million at December 31, 2005. MDU Construction Services expects to complete a significant amount of this backlog during the year ending December 31, 2007. Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction 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 MDU Construction 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. MDU Construction Services works with the National Electrical Contractors Association and the IBEW on hiring and recruiting qualified lineworkers.

Competition MDU Construction Services operates in a highly competitive business environment. Most of MDU Construction 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 MDU Construction 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 MDU Construction Services will encounter on any particular project. MDU Construction 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 subcontract work accounts for a significant portion of the work performed by MDU Construction 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. MDU Construction Services relies on repeat customers and strives to maintain successful long-term relationships with these customers.

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

The nature of MDU Construction 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. MDU Construction Services has no ongoing remediation related to releases from petroleum storage tanks. MDU Construction 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 MDU Construction Services.

MDU Construction Services did not incur any material environmental expenditures in 2006 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2009.

PIPELINE AND ENERGY SERVICES

General Williston Basin, the regulated business of WBI Holdings, owns and operates over 3,700 miles of transmission, gathering and storage lines and owns or leases and operates 27 compressor stations in the states of Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields 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, 2006, Williston Basin’s net plant investment was approximately $235.5 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.

Bitter Creek, the nonregulated pipeline business, owns and operates gathering facilities in Colorado, Kansas, Montana and Wyoming. Bitter Creek also owns a one-sixth interest in the assets of various offshore gathering pipelines, an associated onshore pipeline and related processing facilities. In total, these facilities include over 1,800 miles of field gathering lines and 83 owned or leased compression facilities, some of which interconnect with Williston Basin’s system. In addition, Bitter Creek provides installation sales and/or leasing of alternate energy delivery systems, primarily propane air facilities, energy efficiency product sales and installation services to large end users.

WBI Holdings, through its energy services business, 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 pipeline and energy services business in the northern Great Plains and Rocky Mountain regions of the United States.

In 2006, WBI Holdings sold Innovatum, a cable and pipeline magnetization and locating company. Certain assets of Innovatum were not included in the sale; however, the Company is actively pursuing a sale of those remaining assets. For additional information regarding Innovatum, see Item 8 - Notes 2 and 3.

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 certain of Williston Basin's firm customers, including its largest customer Montana-Dakota, serve relatively secure residential and commercial end users, they generally all have some price-sensitive end users that could switch to alternate fuels.

Williston Basin transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for the year ended December 31, 2006, represented 66 percent of Williston Basin's currently subscribed firm transportation contract demand. Montana-Dakota has a firm transportation agreement with Williston Basin for a term of five years expiring in June 2012. In addition, Montana-Dakota has a contract with Williston Basin to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements for a term of 20 years expiring in July 2015.

Bitter Creek competes with several pipelines for existing customers and expansions of its systems to gather natural gas in new areas. Bitter Creek’s strong position in the fields in which it operates, its focus on customer service, along with its interconnection with various other pipelines serve to enhance its competitive position.

System Supply Williston Basin's underground natural gas storage facilities have a certificated storage capacity of approximately 353 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. For information regarding natural gas storage legal proceedings, see Item 1A - Risk Factors - Other Risks and Item 8 - Note 20.

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 nontraditional and off-system sources. The Company’s CBNG assets in the Powder River Basin are expected to meet some of these supply needs. For additional information regarding CBNG legal proceedings, see Item 1A - Risk Factors - Environmental and Regulatory Risks and Item 8 - Note 20. 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. For additional information, see Item 8 - Note 19.

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.

Ongoing operations 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 2006 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2009.

NATURAL GAS AND OIL PRODUCTION

General 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 and leaseholds with potential development opportunities, exploratory drilling and the operation and development of natural gas and oil production properties. Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests. Fidelity's business is focused primarily in three core regions: Rocky Mountain, Mid-Continent/ Gulf States and Offshore Gulf of Mexico.

Rocky Mountain

Fidelity's properties in this region are primarily located in the states of Colorado, Montana, North Dakota and Wyoming. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Bonny Field located in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area located in north-central Montana, and the Powder River Basin of Montana and Wyoming. In 2006, Fidelity acquired and became the operator of natural gas and oil properties in the Big Horn Basin of Wyoming. This acquisition was not material to the Company. Fidelity also owns nonoperated natural gas and oil interests and undeveloped acreage positions in this region.

Mid-Continent/Gulf States

This region includes properties in Alabama, Louisiana, New Mexico, Oklahoma and Texas. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Tabasco and Texan Gardens fields of Texas. In addition, Fidelity owns several nonoperated interests and undeveloped acreage positions in this region.

Offshore Gulf of Mexico

Fidelity has nonoperated interests throughout the Offshore Gulf of Mexico. These interests are primarily located in the shallow waters off the coasts of Texas and Louisiana.

Fidelity continues to seek additional reserve and production growth opportunities through the direct acquisition of producing properties, through the 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 Mcf equivalent for 2006, 2005 and 2004, were as follows:

		2006		2005		2004
Natural gas:						
Production (MMcf)		**62,062**		59,378		59,750
Average realized price per Mcf (including hedges)	**$**	**6.03**	$	6.11	$	4.69
Average realized price per Mcf (excluding hedges)	**$**	**5.62**	$	6.87	$	4.90
Oil:						
Production (MBbls)		**2,041**		1,707		1,747
Average realized price per barrel (including hedges)	**$**	**50.64**	$	42.59	$	34.16
Average realized price per barrel (excluding hedges)	**$**	**51.73**	$	48.73	$	37.75
Production costs, including taxes, per Mcf equivalent:						

Lease operating costs	**$ .71**	$ .56	$ .47
Gathering and transportation	**.25**	.20	.17
Production and property taxes	**.47**	.50	.32
	$ 1.43	$ 1.26	$ .96

2006 annual net production by region was as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total
Rocky Mountain	47,879	1,172	54,909	74%
Mid-Continent/Gulf States	8,513	560	11,872	16
Offshore Gulf of Mexico	5,670	309	7,526	10
Total	62,062	2,041	74,307	100%

Well and Acreage Information Gross and net productive well counts and gross and net developed and undeveloped acreage related to Fidelity's interests at December 31, 2006, were as follows:

	Gross*	Net**
Productive wells:		
Natural gas	4,128	3,373
Oil	3,817	240
Total	7,945	3,613
Developed acreage (000's)	749	377
Undeveloped acreage (000's)	963	399

* Reflects well or acreage in which an interest is owned.
** Reflects Fidelity's percentage ownership.

Exploratory and Development Wells The following table reflects activities relating to Fidelity's natural gas and oil wells drilled and/or tested during 2006, 2005 and 2004:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2006	**4**	**1**	**5**	**331**	**1**	**332**	**337**
2005	2	3	5	312	25	337	342
2004	1	4	5	230	20	250	255

At December 31, 2006, there were 222 gross (194 net) wells in the process of drilling or under evaluation, 215 of which were development wells and 7 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.

The information in the table above should not be considered indicative of future performance nor should it be assumed that there is necessarily any correlation between the number of productive wells drilled and quantities of reserves found or economic value. Productive wells are those that produce commercial quantities of hydrocarbons whether or not they produce a reasonable rate of return.

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 explore, develop and operate its properties.

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

The ongoing operations of Fidelity are subject to the Clean Water Act, the Clean Air 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.

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

In connection with the development of CBNG properties, certain capital expenditures were incurred related to water handling. For 2006, capital expenditures for water handling in compliance with current laws and regulations were approximately $800,000 and are estimated to be approximately $3.3 million, $2.6 million and $1.8 million in 2007, 2008 and 2009, respectively. For more information regarding CBNG legal proceedings, see Item 1A - Risk Factors and Item 8 - Note 20.

Reserve Information Fidelity's recoverable proved developed and undeveloped natural gas and oil reserves by region at December 31, 2006, are as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total	PV-10 Value * (in millions)
Rocky Mountain	413,000	19,600	530,800	76%	$ 1,028.7
Mid-Continent/Gulf States	112,700	6,700	152,500	22	343.9
Offshore Gulf of Mexico	12,400	800	17,400	2	63.9
Total reserves	538,100	27,100	700,700	100%	$ 1,436.5

* PV-10 value represents the discounted future net cash flows attributable to proved natural gas and oil reserves before income taxes, discounted at 10 percent. The standardized measure of discounted future net cash flows at Item 8 - Supplementary Financial Information represents the present value of future cash flows attributable to proved natural gas and oil reserves after income taxes, discounted at 10 percent.

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

CONSTRUCTION MATERIALS AND MINING

General Knife River operates construction materials and mining businesses headquartered in Alaska, California, Hawaii, Idaho, Iowa, Minnesota, Montana, North Dakota, Oregon, Texas, Washington and Wyoming. These operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt and liquid asphalt for various commercial and roadway applications; and supply ready-mixed concrete for use in most types of construction, including roads, freeways and bridges as well as homes, schools, shopping centers, office buildings and industrial parks. 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 2006, the Company acquired construction materials and mining businesses with operations in California and Washington. None of these acquisitions was material to the Company.

Knife River continues to investigate the acquisition of other construction materials properties, particularly those relating to construction aggregates and related products such as ready-mixed concrete, asphalt and related construction services.

In August 2005, a new transportation bill called the SAFETEA-LU was signed into law. SAFETEA-LU represents a 31 percent increase over previous funding levels. SAFETEA-LU will provide funding through September 2009. Knife River expects to see average annual funding increases in each of its states of operation ranging from a high of 46 percent in Minnesota to a low of 19 percent in Hawaii. Alaska, Idaho, Montana, North Dakota, Oregon and Wyoming will each see average annual funding increases of slightly more than 30 percent. California will receive a 34 percent average annual increase, Iowa will receive a 25 percent increase, Texas will receive a 37 percent increase and Washington will receive a 27 percent increase.

The construction materials business had approximately $483 million in backlog at December 31, 2006, compared to $465 million at December 31, 2005. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2007.

Competition Knife River's construction materials products are marketed under highly competitive conditions. Price is the principal competitive force to which these products are subject, with service, quality, 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, Description of Property by Issuers Engaged or to be Engaged in Significant Mining Opeartions. 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 1.2 billion tons of aggregate reserves are permitted reserves. The remaining reserves are on properties that are expected to 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, 2006, and sales as of and for the years ended December 31, 2006, 2005 and 2004:

Production Area	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
	owned	leased	owned	leased	**2006**	2005	2004			
Central MN	---	1	52	57	**4,834**	4,608	6,429	105,666	2007-2028	22
Portland, OR	1	4	5	3	**5,862**	5,559	5,821	260,406	2007-2055	44
Northern CA	1	---	7	1	**3,031**	4,180	3,699	49,299	2046	16
Southwest OR	4	8	12	5	**4,425**	3,892	3,405	119,138	2007-2031	27
Eugene, OR	3	3	4	2	**3,026**	2,009	2,003	180,616	2007-2046	60
Hawaii	---	6	---	---	**3,167**	2,891	2,460	71,112	2011-2037	22
Central MT	---	---	5	1	**2,619**	2,408	2,555	42,492	2023	16
Anchorage, AK	---	---	1	---	**1,142**	1,307	1,473	20,830	N/A	18
Northwest MT	---	---	8	5	**1,434**	1,679	1,810	25,479	2007-2020	18
Southern CA	---	2	---	---	**244**	166	518	95,399	2035	Over 100
Bend, OR/WA/ Boise, ID	2	2	5	2	**1,788**	1,731	1,678	105,959	2010-2012	59
Northern MN	2	---	21	20	**520**	968	853	31,655	2007-2016	61
Northern IA/ Southern MN	18	10	8	26	**2,024**	2,063	1,370	66,883	2007-2017	33
North/South Dakota	---	---	2	59	**1,157**	1,205	965	54,060	2007-2031	47
Eastern TX	1	2	---	4	**917**	1,255	1,067	18,127	2007-2012	20
Casper, WY	---	---	---	1	**5**	2	291	978	2007	Over 100
Sales from other sources					**9,405**	11,281	7,047	---		
					45,600	47,204	43,444	1,248,099		

The 1.2 billion tons of estimated aggregate reserves at December 31, 2006, is comprised of 539 million tons that are owned and 709 million tons that are leased. The leases have various expiration dates ranging from 2007 to 2055. Approximately 49 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 20 years, including options for renewal that are at Knife River's discretion. Based on 2006 sales from leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 43 years.

The following table summarizes Knife River's aggregate reserves at December 31, 2006, 2005 and 2004, and reconciles the changes between these dates:

	2006	2005	2004
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,273,696**	1,257,498	1,181,413
Acquisitions	**7,300**	53,495	115,965
Sales volumes*	**(36,195)**	(35,923)	(36,397)
Other	**3,298**	(1,374)	(3,483)
End of year	**1,248,099**	1,273,696	1,257,498

* 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, 2006, Knife River had under ownership or lease, deposits of approximately 10.1 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 to what may be ultimately determined with regard to the Portland, Oregon, Harbor Superfund Site issue described later, 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 most of 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 the management of hazardous wastes and underground storage tank systems. 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 wastes and underground storage tank systems.

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 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 or an asphalt or concrete plant. 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 or processing plants. Land use permit applications generally require that areas proposed for mining or other surface disturbances be surveyed for cultural resources. If any are identified, they must be protected or managed in accordance with regulatory agency requirements.

The most comprehensive 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 land use 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 land use permits 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.

Knife River has been successful in obtaining mining and other land use permit approvals so that sufficient permitted reserves are available to support its operations. For mining operations, this often requires considerable advanced planning to ensure sufficient time is available to complete the permitting process before the newly permitted aggregate 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 SMCRA, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River’s intention is to request bond release as soon as it is deemed possible with all final bond release applications being filed by 2013.

Knife River did not incur any material environmental expenditures in 2006 and, except as to what may be ultimately determined with regard to the issue described below, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2009.

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, see Item 8 - Note 20.

INDEPENDENT POWER PRODUCTION

General Centennial Resources owns, builds and operates electric generating facilities in the United States and has investments in domestic and international transmission and 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. During the fourth quarter of 2006, the Company initiated a plan to sell certain of the domestic assets of Centennial Resources, which largely comprise the independent power production segment. For additional information regarding the potential sale, see Item 8 - Note 3.

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 nonutility 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 may include having a balanced portfolio of generating assets, fuel types, customers and power sales agreements and maintaining low production costs.

Domestic

Centennial Power owns 213 MW of natural gas-fired electric generating facilities near Brush, Colorado. The Brush Generating Facility was purchased in November 2002. Substantially all of the Brush Generating Facility's capacity and energy is sold to PSCo. A PPA with PSCo for 130 MW expires in September 2012. In December 2005, Centennial Power entered into two successive PPAs with PSCo for the sale of 75 MW of capacity and energy. One PPA expires in April 2007 followed by a 10-year PPA expiring in April 2017. The Brush Generating Facility is operated by CEM. PSCo is under contract to supply natural gas to the Brush Generating Facility during the terms of the PPAs.

Centennial Power owns a 67-MW wind-powered electric generating facility 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 PPA with the California Department of Water Resources, which expires in September 2011. AES Wind Generation operates the facility under a contract that expires in October 2013.

In April 2006, Centennial Power purchased the member interests of San Joaquin, which owns a 48-MW natural gas-fired electric generating facility near Lathrop, California. The facility sells all of its capacity and energy under a PPA with Southern California Edison Company that expires in December 2010. CEM operates the San Joaquin generating station. Southern California Edison Company will supply and be responsible for all fuel, fuel transportation and fuel balancing for the San Joaquin generating station during the term of the PPA.

Centennial Power has a 50-percent ownership interest in a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. This ownership interest was purchased in September 2004. The Hartwell Generating Facility sells its output under a PPA with Oglethorpe that expires in May 2019. Oglethorpe reimburses the Hartwell Generating Facility for actual costs of fuel required to operate the plant. 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.

Centennial Power owns a 116-MW coal-fired electric generating facility near Hardin, Montana. The Hardin Generating Facility began operations in early 2006. A PPA 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 Powerex having an option for a two-year extension. Coal for the Hardin Generating Facility is supplied by Westmoreland, at contracted pricing, through a coal sales agreement that expires in December 2008, with Centennial Power having an option of a two-year extension. CEM operates the Hardin Generating Facility.

In October 2006, Centennial Power sold 100 percent of its membership interests in LPP to Hobbs Power. Centennial Power formed LPP to develop a 550-MW natural gas-fired electric generating facility to be built near Hobbs, New Mexico. CEM will construct the facility. CEM also is in negotiations to operate the facility. Onsite construction is expected to begin by the spring of 2007 with plant operations scheduled to commence the summer of 2008. Revenues associated with the sale are expected to be recognized over the period of construction of the new facility.

CEM provides analysis, design, construction, refurbishment, and operation and maintenance services related to electric generating facilities. CEM is headquartered in Lafayette, Colorado, and was acquired in April 2004. In addition to operating the Brush, Hardin and San Joaquin facilities, CEM provides operation and maintenance services for third-party customers owning approximately 510 MW of generating capacity. The operation and maintenance contracts related to these third-party customers have expirations ranging from July 2007 to June 2009.

Environmental Matters Centennial Power has several operations that require federal and state environmental permits. The Brush Generating Facility, Hartwell Generating Facility, Hardin Generating Facility and San Joaquin 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 two Title V Operating Permits, each 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. The Hardin Generating Facility is operating under an air quality permit issued by the state of Montana. The Mountain View wind-powered electric generating facility has obtained necessary siting authority and land leases for its operations. It has minor requirements related to California state spill prevention and control regulations. The San Joaquin Generating Facility has a Title V Operating Permit issued by the regional air district in California for a period of five years under a program approved by the EPA. The facility also has waste water discharge agreements with the cities of Lathrop and Manteca, which are issued for one-year and three-year periods, respectively.

Centennial Power's operations did not incur any material environmental expenditures in 2006 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2009.

International

Centennial International owns 49.99 percent of Carib Power. Carib Power was acquired in February 2004. Carib Power, through a wholly owned subsidiary, owns a 225-MW natural gas-fired electric generating facility 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 PPA expires in September 2029. T&TEC also is under contract to supply natural gas to the Trinity Generating Facility during the term of the PPA. On December 29, 2006, the Company entered into an agreement to sell its interest in Carib Power. Closing is expected to occur in the first quarter of 2007.

On August 16, 2006, MDU Brasil acquired ownership interests in companies owning three electric transmission lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric transmission lines, which are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments and have between 24 and 26 years remaining under the contracts. Alusa, Brascan and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. Alusa is the operating partner for the transmission lines. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

MDU Brasil was a party to a joint venture agreement with a Brazilian firm under which the parties agreed to develop electric generation and transmission, steam generation and coal mining projects in Brazil. The Company's 49 percent interest in MPX was sold in June 2005. For information regarding the sale of MPX, see Item 8 - Note 4. In November 2005, the joint venture relationship was terminated.

For additional information regarding international operations, see Item 1A - Risk Factors - Risks Relating to Foreign Operations.

Environmental Matters 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.

This business segment's international operations did not incur any material environmental expenditures in 2006 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2009.

ITEM 1A. RISK FACTORS

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents that it files with the SEC. The 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, that cannot be predicted or controlled.

These factors include: 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 and service 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, startup 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, startup and operation of power generation facilities involves many risks, including delays; breakdown or failure of equipment; competition; inability to obtain required governmental permits and approvals; inability to negotiate acceptable acquisition, construction, fuel supply, off-take, transmission or other material agreements; changes in market price for power; cost increases; 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.

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 economic 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 sources 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
- A deterioration in capital market conditions
- Volatility in commodity prices
- Terrorist attacks

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.

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 ongoing litigation and administrative proceedings and compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions and CBNG 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 injunctive relief or other remedies to enforce applicable environmental laws and regulations. The Company cannot predict the outcome (financial or operational) of any related litigation or administrative proceedings 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.

One of the Company's subsidiaries is subject to ongoing litigation and administrative proceedings in connection with its CBNG development activities. These proceedings have caused delays in CBNG drilling activity, and the ultimate outcome of the actions could have a material negative effect on existing CBNG operations and/or the future development of its CBNG properties.

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 CBNG 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 negative effect on Fidelity's existing CBNG operations and/or the future development of its CBNG properties.

The BER in March 2006 issued a decision in a rulemaking proceeding, initiated by the NPRC, that amends the non-degradation policy applicable to water discharged in connection with CBNG operations. The amended policy includes additional limitations on factors deemed harmful, thereby restricting water discharges even further than under previous standards. Due in part to this amended policy, in May 2006, the Northern Cheyenne Tribe commenced litigation in Montana state court challenging two five-year water discharge permits that the Montana DEQ granted to Fidelity in February 2006 and which are critical to Fidelity's ability to manage water produced under present and future CBNG operations. If these permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

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.

Other Risks

The Company's pending acquisition of Cascade may be delayed or may not occur if certain conditions are not satisfied. Upon completion of the acquisition, if the Company is unable to integrate the Cascade operations effectively, its future financial position or results of operations may be adversely affected.

The Company has entered into a definitive merger agreement to acquire Cascade. The total value of the transaction, including the assumption of certain indebtedness, is approximately $475 million. The completion of the acquisition is subject to the approval of various regulatory authorities and the satisfaction of other customary closing conditions. The Company's pending acquisition of Cascade may be delayed or may not occur if the Company is unable to timely obtain necessary regulatory approvals, satisfy closing conditions or obtain financing. If the Company is unable to integrate the Cascade operations effectively, its future financial position or results of operations may be adversely affected.

One of the Company's subsidiaries is engaged in litigation with a nonaffiliated natural gas producer that has been conducting drilling and production operations that the subsidiary believes is causing diversion and loss of quantities of storage gas from one of its storage reservoirs. If the subsidiary is not able to obtain relief through the courts or the regulatory process, its storage operations could be materially and adversely affected.

Williston Basin has filed suit in Federal court in Montana seeking to recover unspecified damages from Anadarko and its wholly owned subsidiary, Howell, and to enjoin Anadarko and Howell's present and future production operations in and near the EBSR. Based on relevant information, including reservoir and well pressure data, Williston Basin believes that EBSR pressures have decreased and that the storage reservoir has lost gas and continues to lose gas as a result of Anadarko and Howell's drilling and production activities. In related litigation, Howell filed suit in Wyoming state district court against Williston Basin asserting that it is entitled to produce any gas that might escape from Williston Basin's storage reservoir. Williston Basin has answered Howell's complaint and has asserted counterclaims. Williston Basin has sought preliminary injunctive relief seeking to enjoin the subject Anadarko and Howell wells from taking Williston Basin's storage gas. If Williston Basin is unable to obtain timely relief through the courts or regulatory process, its present and future gas storage operations, including its ability to meet its contractual storage and transportation obligations to customers, could be materially and adversely affected.

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 construction 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.

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

All of the Company’s businesses are subject to increased competition. Construction 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 also are experiencing increased competitive pressures as a result of consumer demands, technological advances, increased natural gas prices 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. The independent power production industry has many competitors in the operation, acquisition and development of power generation facilities. The increase in competition could negatively affect the Company’s results of operations and financial condition.

Other factors that could impact the Company’s businesses.

The following are other factors that should be considered for a better understanding of the financial condition of the 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- and construction-related 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 (including related energy 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 and the internal controls of acquired companies
- The ability to attract and retain skilled labor and key personnel
- Increases in employee and retiree benefit costs

ITEM 1B. UNRESOLVED COMMENTS

The Company has no unresolved comments with the SEC.

ITEM 3. LEGAL PROCEEDINGS

For information regarding legal proceedings of the Company, see Item 8 - Note 20.

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 2006.

PART II

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 under the symbol "MDU." The price range of the Company's common stock as reported by The Wall Street Journal composite tape during 2006 and 2005 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Per Share
2006			
First quarter	**$24.53**	**$21.85**	**$.1267**
Second quarter	**24.99**	**22.53**	**.1267**
Third quarter	**25.40**	**22.25**	**.1350**
Fourth quarter	**27.04**	**22.29**	**.1350**
			$.5234
2005			
First quarter	$19.00	$16.99	$.1200
Second quarter	19.56	17.57	.1200
Third quarter	24.05	18.72	.1267
Fourth quarter	24.75	20.57	.1267
			$.4934

Note: Common stock share amounts reflect the Company’s three-for-two common stock split effected in July 2006.

As of December 31, 2006, the Company's common stock was held by approximately 15,400 stockholders of record.

ITEM 6. SELECTED FINANCIAL DATA

Operating Statistics	**2006**	2005	2004	2003	2002	2001
Selected Financial Data						
Operating revenues (000's):						
Electric	$ **187,301**	$ 181,238	$ 178,803	$ 178,562	$ 162,616	$ 168,837
Natural gas distribution	**351,988**	384,199	316,120	274,608	186,569	255,389
Construction services	**987,582**	687,125	426,821	434,177	458,660	364,750
Pipeline and energy services	**443,720**	477,311	354,164	250,897	163,466	528,262
	483,952	439,367	342,840	264,358	203,595	209,831

Natural gas and oil production						
Construction materials and mining	**1,877,021**	1,604,610	1,322,161	1,104,408	962,312	806,899
Independent power production	**66,145**	48,508	43,059	32,261	2,998	---
Other	**8,117**	6,038	4,423	2,728	3,778	---
Intersegment eliminations	**(335,142)**	(375,965)	(272,199)	(191,105)	(114,249)	(113,188)
	$ 4,070,684	$ 3,452,431	$ 2,716,192	$ 2,350,894	$ 2,029,745	$ 2,220,780
Operating income (000's):						
Electric	**$ 27,716**	$ 29,038	$ 26,776	$ 35,761	$ 33,915	$ 38,731
Natural gas distribution	**8,744**	7,404	1,820	6,502	2,414	3,576
Construction services	**50,651**	28,171	(5,757)	12,885	13,980	25,199
Pipeline and energy services	**57,133**	43,507	29,570	37,064	40,118	30,255
Natural gas and oil production	**231,802**	230,383	178,897	118,347	85,555	103,943
Construction materials and mining	**156,104**	105,318	86,030	91,579	91,430	71,451
Independent power production	**(510)**	4,916	8,126	10,610	(1,176)	---
Other	**596**	420	136	1,233	908	---
	$ 532,236	$ 449,157	$ 325,598	$ 313,981	$ 267,144	$ 273,155
Earnings on common stock (000's):						
Electric	**$ 14,401**	$ 13,940	$ 12,790	$ 16,950	$ 15,780	$ 18,717
Natural gas distribution	**5,680**	3,515	2,182	3,869	3,587	677
Construction services	**27,851**	14,558	(5,650)	6,170	6,371	12,910
Pipeline and energy services	**32,126**	22,867	13,806	19,852	20,099	16,768
Natural gas and oil production	**145,657**	141,625	110,779	70,767	53,192	63,178
Construction materials and mining	**85,702**	55,040	50,707	54,261	48,702	43,199
Independent power production	**4,513**	22,921	26,309	11,415	307	---
Other	**1,302**	707	321	606	652	---
Earnings on common stock before loss from discontinued operations and cumulative effect of accounting change	**317,232**	275,173	211,244	183,890	148,690	155,449
Loss from discontinued operations, net of tax	**(2,160)**	(775)	(4,862)	(1,694)	(1,002)	(362)
Cumulative effect of accounting change	**---**	---	---	(7,589)	---	---

	$ 315,072	$ 274,398	$ 206,382	$ 174,607	$ 147,688	$ 155,087
Earnings per common share before discontinued operations and cumulative effect of accounting change - diluted	**$ 1.75**	$ 1.53	$ 1.20	$ 1.09	$ .93	$ 1.02
Discontinued operations, net of tax	**(.01)**	---	(.03)	(.01)	(.01)	---
Cumulative effect of accounting change	**---**	---	---	(.04)	---	---
	$ 1.74	$ 1.53	$ 1.17	$ 1.04	$ .92	$ 1.02
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	**181,392**	179,490	176,117	168,690	160,295	152,705
Dividends per common share	**$ .5234**	$ .4934	$ .4667	$ .4400	$ .4177	$ .4000
Book value per common share	**$ 11.88**	$ 10.43	$ 9.39	$ 8.44	$ 7.71	$ 7.07
Market price per common share (year end)	**$ 25.64**	$ 21.83	$ 17.79	$ 15.87	$ 11.47	$ 12.51
Market price ratios:						
Dividend payout	**30%**	32%	40%	43%	45%	39%
Yield	**2.1%**	2.3%	2.7%	2.9%	3.7%	3.3%
Price/earnings ratio	**14.7x**	14.3x	15.2x	15.4x	12.5x	12.3x
Market value as a percent of book value	**215.8%**	209.2%	189.4%	188.1%	148.8%	177.0%
Profitability Indicators						
Return on average common equity	**15.6%**	15.7%	13.2%	13.0%	12.5%	15.3%
Return on average invested capital	**10.6%**	10.8%	9.4%	8.9%	8.6%	10.1%
First mortgage bond interest coverage	**26.0x**	10.2x	7.1x	7.4x	7.7x	8.5x
Fixed charges coverage, including preferred dividends	**6.3x**	6.1x	4.7x	4.7x	4.8x	5.3x
General						
Total assets (000's)	**$ 4,903,474**	$ 4,423,562	$ 3,733,521	$ 3,380,592	$ 2,996,921	$ 2,675,978
Long-term debt, net of current maturities (000's)	**$ 1,170,548**	$ 1,104,752	$ 873,441	$ 939,450	$ 819,558	$ 783,709
Redeemable preferred stock (000's)	**$ ---**	$ ---	$ ---	$ ---	$ 1,300	$ 1,400
Capitalization ratios:						
Common equity	**65%**	63%	65%	60%	60%	58%
Preferred stocks	**---**	---	1	1	1	1
Long-term debt, net of current maturities	**35**	37	34	39	39	41
	100%	100%	100%	100%	100%	100%

NOTE: Common stock share amounts reflect the Company's three-for-two common stock splits effected in July 2006 and October 2003.

Operating Statistics	**2006**	2005	2004	2003	2002	2001
Electric						
Retail sales (thousand kWh)	**2,483,248**	2,413,704	2,303,460	2,359,888	2,275,024	2,177,886
Sales for resale (thousand kWh)	**483,944**	615,220	821,516	841,637	784,530	898,178
Electric system summer generating and firm purchase capability - kW (Interconnected system)	**547,485**	546,085	544,220	542,680	500,570	500,820
Demand peak - kW (Interconnected system)	**485,456**	470,470	470,470	470,470	458,800	453,000
Electricity produced (thousand kWh)	**2,218,059**	2,327,228	2,552,873	2,384,884	2,316,980	2,469,573
Electricity purchased (thousand kWh)	**833,647**	892,113	794,829	929,439	857,720	792,641
Average cost of fuel and purchased power per kWh	**$ .022**	$ .020	$ .019	$ .019	$ .018	$ .018
Natural Gas Distribution						
Sales (Mdk)	**34,553**	36,231	36,607	38,572	39,558	36,479
Transportation (Mdk)	**14,058**	14,565	13,856	13,903	13,721	14,338
Weighted average degree days - % of previous year's actual	**95%**	100%	94%	96%	109%	95%
Pipeline and Energy Services						
Transportation (Mdk)	**130,889**	104,909	114,206	90,239	99,890	97,199
Gathering (Mdk)	**87,135**	82,111	80,527	75,861	72,692	61,136
Natural Gas and Oil Production						
Production:						
Natural gas (MMcf)	**62,062**	59,378	59,750	54,727	48,239	40,591
Oil (MBbls)	**2,041**	1,707	1,747	1,856	1,968	2,042
Average realized prices (including hedges):						
Natural gas (per Mcf)	**$ 6.03**	$ 6.11	$ 4.69	$ 3.90	$ 2.72	$ 3.78
Oil (per barrel)	**$ 50.64**	$ 42.59	$ 34.16	$ 27.25	$ 22.80	$ 24.59
Proved reserves:						
Natural gas (MMcf)	**538,100**	489,100	453,200	411,700	372,500	324,100
Oil (MBbls)	**27,100**	21,200	17,100	18,900	17,500	17,500
Construction Materials and Mining						

Construction materials (000's):						
Aggregates (tons sold)	**45,600**	47,204	43,444	38,438	35,078	27,565
Asphalt (tons sold)	**8,273**	9,142	8,643	7,275	7,272	6,228
Ready-mixed concrete (cubic yards sold)	**4,588**	4,448	4,292	3,484	2,902	2,542
Recoverable aggregate reserves (tons)	**1,248,099**	1,273,696	1,257,498	1,181,413	1,110,020	1,065,330
Coal (000's):						
Sales (tons)	**---***	---*	---*	---*	---*	1,171*
Lignite deposits (tons)	**10,100***	11,400*	11,400*	26,910*	37,761*	56,012*
Independent Power Production**						
Net generation capacity - kW	**437,600**	279,600	279,600	279,600	213,000	---
Electricity produced and sold (thousand kWh)	**830,212**	254,618	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

The Company's strategy is to apply its expertise in energy and transportation infrastructure industries to increase market share, increase profitability and enhance shareholder value through:

- Organic growth as well as a continued disciplined approach to the acquisition of well-managed companies and properties
- The elimination of system-wide cost redundancies through increased focus on integration of operations and standardization and consolidation of various support services and functions across companies within the organization
- The development of projects that are accretive to earnings per share and return on invested capital

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities and the issuance from time to time of debt securities and the Company's equity securities. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments. Net capital expenditures are comprised of (A) capital expenditures plus (B) acquisitions (including the issuance of the Company's equity securities, less cash acquired) less (C) net proceeds from the sale or disposition of property.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy to customers while working with them to ensure efficient usage. Both the electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations and through selected acquisitions of companies and properties at prices that will provide an opportunity for the Company to earn a competitive return on investment. The natural gas distribution segment also continues to pursue growth by expanding its energy-related services.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and permitted returns on investment as well as subject to certain operational regulations at the federal level. The ability of these segments to grow through acquisitions is subject to significant competition from other energy providers. In addition, as to the electric business, the ability of this segment to grow its service territory and customer base is affected by significant competition from other energy providers, including rural electric cooperatives.

Construction Services

Strategy Provide a competitive return on investment while operating in a competitive industry by: building new and strengthening existing customer relationships; effectively controlling costs; recruiting, developing and retaining talented employees; focusing business development efforts on project areas that will permit higher margins; and properly managing risk. This segment continuously seeks opportunities to expand through strategic acquisitions.

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls and retention of key personnel are ongoing challenges.

Pipeline and Energy Services

Strategy Leverage the segment's existing expertise in energy infrastructure and related services to increase market share and profitability through optimization of existing operations, internal growth, and acquisitions of energy-related assets and companies. Incremental and new growth opportunities include: access to new sources of natural gas for storage, gathering and transportation services; expansion of existing gathering and transmission facilities; and incremental expansion of pipeline capacity to allow customers access to more liquid and higher-priced markets.

Challenges Energy price volatility; natural gas basis differentials; regulatory requirements; ongoing litigation; recruitment and retention of a skilled workforce; and increased competition from other natural gas pipeline and gathering companies.

Natural Gas and Oil Production

Strategy Apply new technology and leverage existing exploration and production expertise, with a focus on operated properties, to increase production and reserves from existing leaseholds, and to seek additional reserves and production opportunities in new areas to further diversify the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment's goal is to increase both production and reserves over the long term so as to generate competitive returns on investment.

Challenges Fluctuations in natural gas and oil prices; ongoing environmental litigation and administrative proceedings; timely receipt of necessary permits and approvals; recruitment and retention of a skilled workforce; availability of drilling rigs, auxiliary equipment and industry-related field services; and increased competition from many of the larger natural gas and oil companies.

Construction Materials and Mining

Strategy Focus on high growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; and continue growth through acquisitions. Ongoing efforts to increase margin are being pursued through the implementation of a variety of continuous improvement programs, including corporate purchasing of equipment, parts and commodities (asphalt oil, diesel fuel, cement and other materials), negotiation of contract price escalation provisions and the utilization of national purchasing accounts. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to adequate quantities of permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its presence in the higher-margin materials business (rock, sand, gravel, asphalt cement, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Price volatility with respect to, and availability of, raw materials such as asphalt oil, diesel fuel and cement; recruitment and retention of a skilled workforce; and management of fixed price construction contracts, which are particularly vulnerable to volatility of these energy and material prices. Some of our markets are likely to be affected by the slowdown in housing, which should be partially mitigated by increased commercial spending.

Independent Power Production

Strategy Divest of certain domestic assets due to the increased market demand for independent power production assets, combined with the Company's desire to efficiently fund its future capital needs.

Challenges Overall business challenges for this segment include: the risks and uncertainties associated with the sale of the domestic assets; construction, startup and operation of power plant facilities; and foreign currency fluctuation and political risk in the countries where this segment does business.

For further information on the risks and challenges the Company faces as it pursues its growth strategies and other factors that should be considered for a better understanding of the Company's financial condition, see item 1A - Risk Factors. For further information on each segment's key growth strategies, projections and certain assumptions, see Prospective Information.

For information pertinent to various commitments and contingencies, see Item 8 - 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,		**2006**		2005		2004
		(Dollars in millions, where applicable)				
Electric	**$**	**14.4**	$	13.9	$	12.8
Natural gas distribution		**5.7**		3.5		2.2
Construction services		**27.8**		14.6		(5.6)
Pipeline and energy services		**32.1**		22.9		13.8
Natural gas and oil production		**145.7**		141.6		110.8
Construction materials and mining		**85.7**		55.1		50.7
Independent power production		**4.5**		22.9		26.3
Other		**1.3**		.7		.3
Income from continuing operations		**317.2**		275.2		211.3
Loss from discontinued operations, net of tax		(2.1)		(.8)		(4.9)
Earnings on common stock	**$**	**315.1**	$	274.4	$	206.4
Earnings per common share - basic:						
Earnings before discontinued operations	**$**	**1.76**	$	1.54	$	1.21
Discontinued operations, net of tax		(.01)		---		(.03)
Earnings per common share - basic	**$**	**1.75**	$	1.54	$	1.18
Earnings per common share - diluted:						
Earnings before discontinued operations	**$**	**1.75**	$	1.53	$	1.20
Discontinued operations, net of tax		(.01)		---		(.03)
Earnings per common share - diluted	**$**	**1.74**	$	1.53	$	1.17
Return on average common equity		15.6%		15.7%		13.2%

2006 compared to 2005 Consolidated earnings for 2006 increased $40.7 million from the comparable period largely due to:

- Higher earnings from construction, aggregate and asphalt operations, and earnings from companies acquired since the comparable prior period at the construction materials and mining business
- Higher construction workloads and margins, as well as earnings from acquisitions made since the comparable prior period at the construction services business
- Higher transportation and gathering volumes, higher storage services revenue and higher gathering rates at the pipeline and energy services segment
- Increased oil and natural gas production of 20 percent and 5 percent, respectively, and higher average realized oil prices of 19 percent, partially offset by higher depreciation, depletion and amortization expense and higher lease operating expense at the natural gas and oil production business

Partially offsetting the increase were decreased earnings from equity method investments, which largely reflect the absence in 2006 of the 2005 $15.6 million benefit from the sale of the Termoceara Generating Facility at the independent power production business.

2005 compared to 2004 Consolidated earnings for 2005 increased $68.0 million from the comparable period largely due to:

- Higher average realized natural gas prices of 30 percent and higher average realized oil prices of 25 percent at the natural gas and oil production business
- Increased outside and inside electrical workloads and margins, as well as earnings from acquisitions made in the second quarter of 2005 at the construction services business
- The benefit from the resolution of a rate proceeding of $5.0 million (after tax), which included a reduction to depreciation, depletion and amortization expense; and the absence in 2005 of the 2004 $4.0 million (before and after tax) noncash goodwill impairment relating to the Company’s cable and pipeline magnetization and location business reflected in loss from discontinued operations, as well as the 2004 $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

Partially offsetting the increase in earnings was the absence in 2005 of the favorable resolution of federal and related state income tax matters realized in 2004, which resulted in a benefit of $8.3 million (after tax), including interest.

FINANCIAL AND OPERATING DATA

Below are key financial and operating data for each of the Company's businesses.

Electric

Years ended December 31,	**2006**	2005	2004
	(Dollars in millions, where applicable)		
Operating revenues	**$ 187.3**	$ 181.2	$ 178.8
Operating expenses:			
Fuel and purchased power	**67.4**	63.6	64.6
Operation and maintenance	**62.8**	59.5	59.0
Depreciation, depletion and amortization	**21.4**	20.8	20.2
Taxes, other than income	**8.0**	8.3	8.2
	159.6	152.2	152.0
Operating income	**27.7**	29.0	26.8
Earnings	**$ 14.4**	$ 13.9	$ 12.8
Retail sales (million kWh)	**2,483.2**	2,413.7	2,303.5
Sales for resale (million kWh)	**484.0**	615.2	821.5

Average cost of fuel and purchased power per kWh	**$**	**.022**	$	.020	$	.019

2006 compared to 2005 Electric earnings increased $500,000 (3 percent) compared to the prior year due to:

- Higher retail sales margins, primarily due to increased volumes of 3 percent and lower demand charges related to a PPA that expired in the fourth quarter of 2006
- Lower income taxes of $700,000
- Lower interest expense of $600,000 (after tax), resulting from lower average interest rates due to the purchase and redemption of certain higher cost long-term debt

Partially offsetting the increase in earnings were:

- Decreased sales for resale margins due to lower average rates of 15 percent and decreased volumes of 21 percent, largely due to plant availability
- Higher operation and maintenance expense of $1.7 million (after tax), primarily the result of scheduled maintenance outages at electric generating stations

2005 compared to 2004 Electric earnings increased $1.1 million (9 percent) compared to the prior year due to:

- Higher retail sales margins, largely due to 5 percent higher volumes, primarily residential, commercial and industrial, partially offset by increased fuel and purchased power costs
- Higher sales for resale margins, primarily the result of higher average realized prices of 22 percent and lower fuel and purchased power-related costs, offset in part by decreased sales for resale volumes of 25 percent
- Lower interest expense of $900,000 (after tax)

Partially offsetting the increase in earnings was the absence in 2005 of the favorable resolution of federal and related state income tax matters realized in 2004 of $1.7 million (after tax), including interest.

Natural Gas Distribution

Years ended December 31,		**2006**		2005		2004
		(Dollars in millions, where applicable)				
Operating revenues	**$**	**352.0**	$	384.2	$	316.1
Operating expenses:						
Purchased natural gas sold		**259.5**		315.4		251.1
Operation and maintenance		**68.4**		46.0		48.3
Depreciation, depletion and amortization		**9.8**		9.6		9.4
Taxes, other than income		**5.6**		5.8		5.5
		343.3		376.8		314.3
Operating income		**8.7**		7.4		1.8
Earnings	**$**	**5.7**	$	3.5	$	2.2
Volumes (MMdk):						
Sales		**34.5**		36.2		36.6
Transportation		**14.1**		14.6		13.9
Total throughput		**48.6**		50.8		50.5
Degree days (% of normal)*		**86.7%**		90.9%		90.7%
Average cost of natural gas, including transportation, per dk	**$**	**7.51**	$	8.71	$	6.86

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

2006 compared to 2005 The natural gas distribution business experienced an increase in earnings of $2.2 million (62 percent) compared to the prior year due to:

- Increased nonregulated earnings of $1.7 million (after tax) from energy-related services
- Lower income taxes of $900,000

Partially offsetting this increase were higher payroll-related expenses of $900,000 (after tax), largely due to an early retirement program.

The pass-through of lower natural gas prices is reflected in the decrease in both sales revenues and purchased natural gas sold. The decrease in sales revenues was partially offset by revenues from nonregulated energy-related services. Nonregulated energy-related services also contributed to the operation and maintenance expense increase.

2005 compared to 2004 The natural gas distribution business experienced an increase in earnings of $1.3 million (61 percent) compared to the prior year due to:

- Higher average realized rates of $2.0 million (after tax), largely the result of rate increases approved by various state public service commissions
- Decreased operation and maintenance expenses, largely payroll-related costs

The increase was partially offset by the absence in 2005 of the favorable resolution of federal and related state income tax matters realized in 2004 of $3.0 million (after tax), including interest.

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

Construction Services

Years ended December 31,	**2006**	2005	2004
(Dollars in millions)			
Operating revenues	**$ 987.6**	$ 687.1	$ 426.8
Operating expenses:			
Operation and maintenance	**892.7**	625.1	405.6
Depreciation, depletion and amortization	**15.4**	13.4	11.1
Taxes, other than income	**28.8**	20.4	15.8
	936.9	658.9	432.5
Operating income (loss)	**50.7**	28.2	(5.7)
Earnings (loss)	**$ 27.8**	$ 14.6	$ (5.6)

2006 compared to 2005 Construction services earnings increased $13.2 million (91 percent) due to:

- Higher construction workloads and margins of $7.3 million (after tax), largely in the Southwest region
- Earnings from acquisitions made since the comparable prior period, which contributed approximately 43 percent of the earnings increase
- Higher equipment sales and rentals

Partially offsetting this increase were higher general and administrative expenses of $1.7 million (after tax), primarily payroll related.

2005 compared to 2004 Construction services realized $14.6 million in earnings compared to a $5.6 million loss for the prior year. The $20.2 million increase in earnings is due to:

· Higher outside and inside electrical workloads and margins of $12.8 million (after tax)
· Earnings from businesses acquired during the second quarter of 2005, which contributed approximately 19 percent of the earnings increase
· Higher equipment sales and rentals
· Lower general and administrative expenses of $1.4 million (after tax), largely lower severance-related expenses

Pipeline and Energy Services

Years ended December 31,	**2006**	2005	2004
	(Dollars in millions)		
Operating revenues:			
Pipeline	**$ 102.8**	$ 85.5	$ 87.2
Energy services	**340.9**	391.8	267.0
	443.7	477.3	354.2
Operating expenses:			
Purchased natural gas sold	**311.0**	363.7	249.8
Operation and maintenance	**52.8**	49.8	47.5
Depreciation, depletion and amortization	**13.3**	12.5	17.6
Taxes, other than income	**9.5**	7.8	7.6
Asset impairments	**---**	---	2.1
	386.6	433.8	324.6
Operating income	**57.1**	43.5	29.6
Income from continuing operations	**32.1**	22.9	13.8
Loss from discontinued operations, net of tax	**(2.1)**	(.8)	(4.9)
Earnings	**$ 30.0**	$ 22.1	$ 8.9
Transportation volumes (MMdk):			
Montana-Dakota	**31.0**	31.4	32.5
Other	**99.9**	73.5	81.7
	130.9	104.9	114.2
Gathering volumes (MMdk)	**87.1**	82.1	80.5

2006 compared to 2005 Pipeline and energy services earnings increased $7.9 million (36 percent) due largely to:

· Higher transportation and gathering volumes ($5.3 million after tax)
· Higher storage services revenue ($5.8 million after tax)
· Higher gathering rates ($3.2 million after tax)

Partially offsetting this increase in earnings were:

· Absence in 2006 of the benefit from the resolution of a rate proceeding of $5.0 million (after tax) recorded in 2005, which was largely offset by the benefit from the resolution of a rate proceeding of $4.1 million (after tax) recorded in 2006, both of which included a reduction to depreciation, depletion and amortization expense. For further information, see Item 8 - Note 19.
· Higher operation and maintenance expense, primarily due to the natural gas storage litigation. For further information, see Item 8 - Note 20.
· An increased loss from discontinued operations of $1.3 million (after tax), related to Innovatum. For further information, see Item 8 - Note 2.

The decrease in energy services revenues and purchased natural gas sold reflects the effect of lower natural gas prices.

2005 compared to 2004 Pipeline and energy services earnings increased $13.2 million (147 percent) due largely to:

- The benefit from the resolution of a rate proceeding of $5.0 million (after tax), as previously discussed
- The absence in 2005 of the 2004 $4.0 million (before and after tax) noncash goodwill impairment reflected in loss from discontinued operations, and the 2004 $1.3 million (after tax) asset valuation adjustment, both as previously discussed
- Higher gathering rates of $4.4 million (after tax)
- Lower net interest expense of $700,000 (after tax)

Partially offsetting the increase in earnings were:

- The absence in 2005 of the favorable resolution of federal and related state income tax matters realized in 2004 of $1.6 million (after tax), including interest
- Lower transportation and storage rates in 2005 of $1.5 million (after tax), largely the result of a FERC rate order received in July 2003 and a rehearing order received in May 2004, which resulted in lower rates effective July 1, 2004

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

Natural Gas and Oil Production

Years ended December 31,		**2006**		2005		2004
		(Dollars in millions, where applicable)				
Operating revenues:						
Natural gas	**$**	**373.9**	$	362.5	$	280.4
Oil		**103.4**		72.7		59.7
Other		**6.7**		4.2		2.8
		484.0		439.4		342.9
Operating expenses:						
Purchased natural gas sold		**6.6**		4.3		2.7
Operation and maintenance:						
Lease operating costs		**52.8**		39.2		33.0
Gathering and transportation		**18.3**		14.1		11.6
Other		**31.9**		31.2		23.1
Depreciation, depletion and amortization		**106.8**		84.8		70.8
Taxes, other than income:						
Production and property taxes		**35.2**		34.8		22.6
Other		**.6**		.6		.2
		252.2		209.0		164.0
Operating income		**231.8**		230.4		178.9
Earnings	**$**	**145.7**	$	141.6	$	110.8
Production:						
Natural gas (MMcf)		**62,062**		59,378		59,750
Oil (MBbls)		**2,041**		1,707		1,747
Average realized prices (including hedges):						
Natural gas (per Mcf)	**$**	**6.03**	$	6.11	$	4.69
Oil (per barrel)	**$**	**50.64**	$	42.59	$	34.16
Average realized prices (excluding hedges):						
Natural gas (per Mcf)	**$**	**5.62**	$	6.87	$	4.90
Oil (per barrel)	**$**	**51.73**	$	48.73	$	37.75

Production costs, including taxes, per equivalent Mcf:						
Lease operating costs	**$**	**.71**	$	.56	$	.47
Gathering and transportation		**.25**		.20		.17
Production and property taxes		**.47**		.50		.32
	$	**1.43**	$	1.26	$	.96

2006 compared to 2005 The natural gas and oil production business experienced an increase in earnings of $4.1 million (3 percent) due to:

- Increased oil production of 20 percent and natural gas production of 5 percent, largely due to the May 2005 South Texas and May 2006 Big Horn acquisitions and increased production in the Rocky Mountain region
- Higher average realized oil prices of 19 percent

Partially offsetting the increase were:

- Higher depreciation, depletion and amortization expense of $13.5 million (after tax) due to higher depletion rates and increased production
- Higher lease operating expense of $8.4 million (after tax), largely acquisition and CBNG-related costs

2005 compared to 2004 The natural gas and oil production business experienced an increase in earnings of $30.8 million (28 percent) due to:

- Higher average realized natural gas prices of 30 percent
- Higher average realized oil prices of 25 percent

Partially offsetting the increase were:

- Higher depreciation, depletion and amortization expense of $8.6 million (after tax) due to higher rates, largely the result of the South Texas acquisition in the second quarter of 2005
- Higher lease operating costs of $5.4 million (after tax), including costs related to the South Texas acquisition, and increased general and administrative expenses of $5.3 million (after tax), including payroll-related costs
- A slight decrease in natural gas and oil production volumes as a result of the effects of hurricanes and normal production declines. Largely offsetting these declines were increases in production from other existing properties due to drilling activity and the South Texas acquisition

Construction Materials and Mining

Years ended December 31,		**2006**		2005		2004
				(Dollars in millions)		
Operating revenues	**$**	**1,877.0**	$	1,604.6	$	1,322.2
Operating expenses:						
Operation and maintenance		**1,593.7**		1,381.9		1,132.3
Depreciation, depletion and amortization		**88.7**		78.0		69.6
Taxes, other than income		**38.5**		39.4		34.3
		1,720.9		1,499.3		1,236.2
Operating income		**156.1**		105.3		86.0
Earnings	**$**	**85.7**	$	55.1	$	50.7
Sales (000's):						
Aggregates (tons)		**45,600**		47,204		43,444
Asphalt (tons)		**8,273**		9,142		8,643

Ready-mixed concrete (cubic yards)	**4,588**	4,448	4,292

2006 compared to 2005 Earnings at the construction materials and mining business increased $30.6 million (56 percent) due to:

· Higher earnings of $18.8 million (after tax) from construction, largely due to increased volumes and margins, the result of strong markets and improvements in Texas
· Increased earnings from aggregate and asphalt operations of $10.4 million (after tax), largely due to higher realized margins, partially offset by lower volumes
· Earnings from companies acquired since the comparable prior period, which contributed approximately 18 percent of the earnings increase
· Higher earnings of $4.2 million (after tax) from ready-mixed concrete operations, largely due to higher margins

Partially offsetting the increase were:

· Higher depreciation, depletion and amortization expense from existing operations of $4.6 million (after tax), primarily due to higher property, plant and equipment balances
· Increased general and administrative expense of $4.2 million (after tax), primarily payroll-related

2005 compared to 2004 Earnings at the construction materials and mining business increased $4.4 million (9 percent) due to:

· Increased ready-mixed concrete margins of $4.7 million (after tax), largely in the Pacific and Northwest regions
· Earnings from companies acquired since the comparable prior period, which contributed less than 5 percent of earnings
· Higher cement volumes

Partially offsetting the increase were:

· Higher depreciation, depletion and amortization expense from existing operations of $3.2 million (after tax), due in part to higher property, plant and equipment balances
· The absence in 2005 of the 2004 favorable resolution of federal and related tax matters of $1.2 million (after tax), including interest

Construction and aggregate margin increases in most regions were largely offset by significantly lower margins in Texas, which included the effects of higher fuel, maintenance and repair costs.

Independent Power Production

Years ended December 31,	**2006**	2005	2004
	(Dollars in millions)		
Operating revenues	**$ 66.1**	$ 48.5	$ 43.1
Operating expenses:			
Fuel and purchased power	**4.7**	---	---
Operation and maintenance	**42.7**	32.0	23.0
Depreciation, depletion and amortization	**15.2**	9.0	9.6
Taxes, other than income	**4.0**	2.6	2.4
	66.6	43.6	35.0
Operating income (loss)	**(.5)**	4.9	8.1
Earnings	**$ 4.5**	$ 22.9	$ 26.3
Net generation capacity - kW*	**437,600**	279,600	279,600

Electricity produced and sold (thousand kWh)*	**830,212**	254,618	204,425

** Excludes equity method investments.*

2006 compared to 2005 Independent power production experienced a decrease in earnings of $18.4 million (80 percent), largely due to:

- Decreased earnings from equity method investments of $11.5 million, which largely reflect the absence in 2006 of the 2005 $15.6 million benefit from the sale of the Termoceara Generating Facility, partially offset by increased earnings from the acquisition of the Brazilian Transmission Lines in August 2006 and increased earnings at the Trinity Generating Facility partially resulting from a one-time benefit due to a tax rate reduction
- Higher interest expense of $5.7 million (after tax), largely due to debt related to the Hardin Generating Facility that was placed into commercial operation in March 2006
- Lower margins of $3.3 million (after tax) related to domestic electric generating facilities, primarily due to lower capacity revenues

For additional information regarding equity method investments, see Item 8 - Note 4.

2005 compared to 2004 Independent power production experienced a decrease in earnings of $3.4 million (13 percent), largely due to:

- The absence in 2005 of 2004 operating income from the Termoceara Generating Facility, benefits received in 2004 related to foreign currency gains and the effects of the embedded derivative in the Brazilian electric power sales contract were partially offset by a gain from the sale of the equity interest in the Termoceara Generating Facility in June 2005
- Higher general and administrative expense of $1.7 million (after tax), largely consulting and payroll-related costs
- Lower earnings of $900,000 related to a domestic electric generating facility, largely lower capacity revenues and higher gas transportation fees

Partially offsetting the earnings decrease were:

- Earnings from equity method investments acquired since the comparable prior period, which contributed less than 5 percent of earnings
- Lower interest expense of $1.2 million (after tax)
- Increased earnings from wind generation of $1.2 million, largely due to benefits related to higher production

For additional information regarding equity method investments, see Item 8 - Note 4.

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,	**2006**	2005	2004
		(In millions)	
Other:			
Operating revenues	**$ 8.1**	$ 6.0	$ 4.4
Operation and maintenance	**6.1**	5.1	4.0
Depreciation, depletion and amortization	**1.0**	.3	.3
Taxes, other than income	**.4**	.2	---

Intersegment transactions:						
Operating revenues	**$**	**335.1**	$	375.9	$	272.2
Fuel and purchased power		**.3**		---		---
Purchased natural gas sold		**308.1**		354.2		253.7
Operation and maintenance		**26.7**		21.7		18.5

For further information on intersegment eliminations, see Item 8 - Note 15.

PROSPECTIVE INFORMATION
The following information highlights the key growth strategies, projections and certain assumptions for the Company and its subsidiaries 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 changes in revenues and earnings, will in fact be achieved. Please refer to assumptions contained in this section as well as the various important factors listed in Item 1A - Risk Factors. Changes in such assumptions and factors could cause actual future results to differ materially from the Company's targeted growth, revenue and earnings projections.

MDU Resources Group, Inc.

- Earnings per common share for 2007, diluted, are projected in the range of $1.50 to $1.70.

- The Company expects the percentage of 2007 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 - 35 percent to 40 percent
  - Fourth quarter - 25 percent to 30 percent

- The Company's long-term compound annual growth goals on earnings per share from operations are in the range of 7 percent to 10 percent.

Electric

- The Company is analyzing potential projects for accommodating load growth and replacing an expired purchased power contract with company-owned generation. This will add to base-load capacity and rate base. New generation is projected to be on line in late 2011 or early 2012. A major commitment decision on the project will be made in mid-2007. A filing in North Dakota for prudence approval of the potential Big Stone II generation project was made in November 2006.

- This business continues to pursue growth by expanding energy-related services.

- Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises.

Natural gas distribution

- As discussed in Item 8 - Note 22, the Company has entered into a definitive merger agreement to acquire Cascade. The acquisition is expected to significantly enhance regulated earnings and cash flows. Regulatory approvals are anticipated in the third quarter of 2007.

- This business continues to pursue growth by expanding energy-related services.

- Montana-Dakota and Great Plains have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. Montana-Dakota and Great Plains intend to protect their service areas and seek renewal of all expiring franchises.

Construction services

· Revenues in 2007 are expected to be comparable to 2006 record levels.

· The Company will continue to focus on costs and efficiencies to improve margins.

· Effective January 1, 2007, CEM became part of this segment. CEM provides analysis, design, construction, refurbishment and operation and maintenance services related to electric generating facilities. CEM recently secured a contract to construct a 550-MW natural gas-fired electric generating facility near Hobbs, New Mexico. It also is in negotiations to operate the facility. Onsite construction is expected to begin by the spring of 2007 with power coming on line by the summer of 2008.

Pipeline and energy services

· Through minor compressor modifications, firm capacity for the Grasslands Pipeline increased from 90,000 Mcf per day to 97,000 Mcf per day effective November 1, 2006. Based on anticipated demand, additional incremental expansions are forecasted over the next few years with the next expansion to 138,000 Mcf per day scheduled for late 2007, depending upon the timing of receiving the necessary regulatory approvals. Through additional compression, the pipeline capacity could ultimately reach 200,000 Mcf per day.

· In 2007, total gathering and transportation throughput is expected to be consistent with 2006 record levels.

Natural gas and oil production

· Long-term compound annual growth goals for production are in the range of 7 percent to 10 percent. In 2007, the Company expects a combined natural gas and oil production increase in that range.

· The Company expects to drill between 300 and 350 wells in 2007, dependent on the timely receipt of regulatory approvals. Currently, this segment's net combined natural gas and oil production ranges from 200,000 Mcf equivalents to 210,000 Mcf equivalents per day.

· Earnings guidance reflects estimated natural gas prices for February through December 2007 as follows:

Index*	**Price Per Mcf**
Ventura	$6.25 to $6.75
NYMEX	$6.75 to $7.25
CIG	$5.25 to $5.75

* Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related to Colorado Interstate Gas Co.'s system.

During 2006, more than three-fourths of natural gas production was priced at non-NYMEX prices, the majority of which was at Ventura pricing.

· Earnings guidance reflects estimated NYMEX crude oil prices for February through December 2007 in the range of $58 to $63 per barrel.

· The Company has hedged approximately 30 percent to 35 percent of its estimated natural gas production for 2007 and approximately 5 percent to 10 percent for 2008. The hedges that are in place as of February 6, 2007, are summarized in the following chart:

Index*	**Period**	**Price Swap or**

Commodity		Outstanding	Forward Notional Volume (MMBtu)	Costless Collar Floor-Ceiling (Per MMBtu)
Natural Gas	Ventura	1/07 - 12/07	1,825,000	$8.00-$11.91
Natural Gas	Ventura	1/07 - 12/07	912,500	$8.00-$11.80
Natural Gas	Ventura	1/07 - 12/07	912,500	$8.00-$11.75
Natural Gas	Ventura	1/07 - 12/07	1,825,000	$7.50-$10.55
Natural Gas	CIG	1/07 - 12/07	1,825,000	$7.40
Natural Gas	CIG	1/07 - 12/07	1,825,000	$7.405
Natural Gas	Ventura	1/07 - 12/07	1,460,000	$8.25-$10.80
Natural Gas	CIG	1/07 - 12/07	912,500	$7.50-$9.12
Natural Gas	Ventura	1/07 - 12/07	1,825,000	$8.29
Natural Gas	Ventura	1/07 - 3/07	450,000	$8.00-$9.80
Natural Gas	Ventura	1/07 - 12/07	1,825,000	$7.85-$9.70
Natural Gas	Ventura	1/07 - 12/07	3,650,000	$7.67
Natural Gas	Ventura	2/07 - 10/07	2,047,500	$7.16
Natural Gas	NYMEX	3/07 - 12/07	1,530,000	$7.50-$8.50
Natural Gas	Ventura	11/07 - 3/08	1,520,000	$8.00-$8.75
Natural Gas	Ventura	1/08 - 12/08	1,830,000	$7.00-$8.45
Natural Gas	CIG	1/08 - 3/08	910,000	$7.00-$7.79
Natural Gas	Ventura	1/08 - 12/08	1,830,000	$7.50-$8.34

* Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related
to Colorado Interstate Gas Co.'s system.

Construction materials and mining

· Revenues in 2007 are expected to be somewhat lower than 2006 record levels.

Independent power production

· The Company has retained a financial adviser with respect to the potential sale of domestic independent power production assets. The Company expects the transaction to close in the second quarter of 2007.

NEW ACCOUNTING STANDARDS

For information regarding new accounting standards, see Item 8 - Note 1, which is incorporated by reference.

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 as well as the reported amounts of revenues and expenses during the reporting period. The Company's significant accounting policies are discussed in Item 8 - 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. 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 and intangibles, excluding natural gas and oil properties, 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 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 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, plus 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, changes in estimates of reserve quantities and changes in operating and development costs could result in a future noncash 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 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 reasonably assured. 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. Inasmuch 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, material and fuel 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, materials and fuel, 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 and intangibles.

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

Entities are required 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, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution and transmission facilities and buildings 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 likelihood 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 the range of time over which the Company may settle the obligation is unknown or cannot be estimated, 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 Company's 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 Net income before depreciation, depletion and amortization is a significant contributor to cash flows from operating activities. The changes in cash flows from operating activities generally follow the results of operations as discussed in Financial and Operating Data and also are affected by changes in working capital. Cash flows provided by operating activities in 2006 increased $176.2 million from the comparable 2005 period, the result of:

· Lower working capital requirements of $70.5 million, largely due to lower cash needs for receivables at the natural gas distribution, natural gas and oil production and construction services businesses
· Higher depreciation, depletion and amortization expense of $43.2 million largely at the natural gas and oil production, construction materials and mining, and the independent power production businesses
· Increased net income of $40.7 million, largely increased earnings at the construction materials and mining, construction services and pipeline and energy services businesses
· Decreased earnings, net of distributions, from equity method investments of $10.3 million, primarily the result of the sale of the Termoceara Generating Facility in 2005

Cash flows provided by operating activities in 2005 increased $50.2 million from the comparable 2004 period, the result of:

· Increased net income of $68.0 million, largely increased earnings at the natural gas and oil production, construction services and pipeline and energy services businesses (Net income in 2004 includes noncash asset impairments of $6.1 million, of which $4.0 million is included in discontinued operations.)
· Higher depreciation, depletion and amortization expense of $19.9 million largely at the natural gas and oil production and construction materials and mining businesses
·

Decreased earnings, net of distributions, from equity method investments of $7.9 million, primarily the result of the sale of the Termoceara Generating Facility

Partially offsetting the increase in cash flows from operating activities were:

· Higher working capital requirements of $54.0 million due in part to:
- Higher receivables, largely increased workloads and acquisition-related increases at the construction services business
- Higher income tax payments due to lower tax depreciation and higher net income
- Partially offset by higher accounts payable due to increased workloads and acquisition-related increases at the construction services business, higher natural gas costs at the natural gas distribution business and increased drilling costs due to increased drilling activity at the natural gas and oil production business

Investing activities Cash flows used in investing activities in 2006 increased $16.3 million compared to the comparable 2005 period, the result of:

· Increased investments largely due to the acquisition of the Brazilian Transmission Lines
· The absence in 2006 of the 2005 proceeds from the sale of the Termoceara Generating Facility

Partially offsetting the increase was a decrease in cash flows used for acquisitions of $87.2 million, largely at the natural gas and oil production and construction materials and mining businesses.

Cash flows used in investing activities in 2005 increased $257.3 million compared to the comparable 2004 period, the result of:

· An increase in net capital expenditures of $329.6 million, due largely to acquisitions (including the acquisition of natural gas and oil production properties in South Texas), the construction of the Hardin Generating Facility and higher ongoing capital expenditures
· The absence in 2005 of the $22.0 million proceeds from notes receivable in 2004

Partially offsetting the increase in cash flows used in investing activities were:

· Lower investments of $56.1 million, including the absence in 2005 of the 2004 investments in the Hartwell and Trinity Generating Facilities
· Proceeds of $38.2 million from the sale of the Termoceara Generating Facility

Financing activities Cash flows related to financing activities in 2006 decreased $198.8 million compared to the comparable 2005 period, primarily the result of an increase in repayment of long-term debt of $208.7 million, partially offset by an increase in proceeds from the issuance of common stock of $10.8 million.

Cash flows provided by financing activities in 2005 increased $202.2 million compared to the comparable 2004 period, primarily the result of an increase in the issuance of long-term debt of $338.5 million due in part to acquisitions and the construction of the Hardin Generating Facility.

The increase in cash flows from financing activities was partially offset by:

· Increased repayment of long-term debt of $68.8 million, including the redemption of $20.9 million of Pollution Control Refunding Revenue bonds and certain scheduled debt repayments
· A decrease in proceeds from the issuance of common stock of $61.0 million reflecting the absence in 2005 of the 2004 proceeds received from an underwritten public offering

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, 2006, certain Pension Plans’ accumulated benefit obligations exceeded these plans’ assets by approximately $3.6 million. Pretax pension expense reflected in the years ended December 31, 2006, 2005 and 2004, was $7.0 million, $6.6 million and $4.1 million, respectively. The Company’s pension expense is currently projected to be approximately $6.0 million to $7.0 million in 2007. Funding for the Pension Plans is actuarially determined. The minimum required contributions for 2006, 2005 and 2004 were approximately $2.6 million, $1.6 million and $1.2 million, respectively. For further information on the Company’s Pension Plans, see Item 8 - Note 17.

Capital expenditures

The Company's capital expenditures for 2004 through 2006 and as anticipated for 2007 through 2009 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2004	2005	**2006**	2007	2008	2009
			(In millions)			
Capital expenditures:						
Electric	$ 19	$ 27	**$ 39**	$ 79	$ 163	$ 192
Natural gas distribution	17	17	**15**	514	51	43
Construction services	9	51	**32**	17	13	13
Pipeline and energy services	38	36	**43**	38	31	33
Natural gas and oil production	112	330	**329**	282	284	289
Construction materials and mining	133	162	**141**	97	86	81
Independent power production	76	136	**33**	3	---	---
Other	4	12	**2**	1	1	1
	408	771	**634**	1,031	629	652
Net proceeds from sale or disposition of property**	(21)	(41)	**(31)**	(9)	(2)	---
Net capital expenditures	387	730	**603**	1,022	627	652
Retirement of long-term debt	38	107	**316**	84	162	73
	$ 425	$ 837	**$ 919**	$ 1,106	$ 789	$ 725

* With the exception of the anticipated acquisition of Cascade in the third quarter of 2007, the estimated 2007 through 2009 capital expenditures reflected in the above table exclude potential future acquisitions and other growth opportunities which are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the above estimates. These amounts also exclude AFUDC equity.

** The estimated 2007 through 2009 net proceeds exclude proceeds related to the disposal of unidentified assets and any potential proceeds related to the previously announced sale of domestic independent power production assets.

Capital expenditures for 2006, 2005 and 2004, in the preceding table include noncash transactions, including the issuance of the Company’s equity securities in connection with acquisitions. The noncash transactions were immaterial in 2006, $46.5 million in 2005 and $33.1 million in 2004.

In 2006, the Company acquired a construction services business in Nevada, natural gas and oil production properties in Wyoming, construction materials and mining businesses in California and Washington, and a natural gas-fired electric generating facility in California at the independent power production segment, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2006, consisting of the Company's common stock and cash, was $133.1 million.

The 2006 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 2007 through 2009 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects
- Further enhancement of natural gas and oil production and reserve growth
- Power generation opportunities, including certain costs for additional electric generating capacity
- Anticipated acquisition of Cascade in the third quarter of 2007
- 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 retirement of long-term debt for the years 2007 through 2009 will be met from various sources, including 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, 2006.

MDU Resources Group, Inc. The Company has a revolving credit agreement with various banks totaling $125 million (with provision for an increase, at the option of the Company on stated conditions and upon regulatory approval, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement at December 31, 2006. The credit agreement supports the Company’s $100 million commercial paper program. Under the Company’s commercial paper program, $25.8 million was outstanding at December 31, 2006. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2011).

The Company’s objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Minor fluctuations in the Company’s credit ratings have not limited, nor would they be expected to limit, the Company’s ability to access the capital markets. In the event of a minor downgrade, the Company may experience 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, it may need to borrow under its credit agreement.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility became too expensive, which the Company 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, including covenants not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments. The Company was in compliance with these covenants and met the required conditions at December 31, 2006. 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.

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its 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, 2006, the Company could have issued approximately $461 million of additional first mortgage bonds.

The Company's coverage of fixed charges including preferred dividends was 6.3 times and 6.1 times for the 12 months ended December 31, 2006 and 2005, respectively. Additionally, the Company's first mortgage bond interest coverage was 26.0 times and 10.2 times for the 12 months ended December 31, 2006 and 2005, respectively. Common stockholders' equity as a percent of total capitalization (net of long-term debt due within one year) was 65 percent and 63 percent at December 31, 2006 and 2005, respectively.

The Company has repurchased, and may from time to time seek to repurchase, outstanding first mortgage bonds through open market purchases or privately negotiated transactions. The Company will evaluate any such transactions in light of then existing market conditions, taking into account its liquidity and prospects for future access to capital. As of December 31, 2006, the Company had $57.0 million of first mortgage bonds outstanding, $30.0 million of which were held by the Indenture trustee for the benefit of the Senior Note holders. At such time as the aggregate principal amount of the Company’s outstanding first mortgage bonds, other than those held by the Indenture trustee, is $20.0 million or less, the Company would have the ability, subject to satisfying certain specified conditions, to require that any debt issued under its Indenture become unsecured and rank equally with all of the Company’s other unsecured and unsubordinated debt (as of December 31, 2006, the only such debt outstanding under the Indenture was $30.0 million in aggregate principal amount of the Company’s 5.98% Senior Notes due in 2033).

On July 27, 2006, the Company entered into a Sales Agency Financing Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 3,000,000 shares of the Company’s common stock, par value $1.00 per share, together with preference share purchase rights appurtenant thereto. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement, which terminates on June 30, 2007. Proceeds from the sale of shares of common stock under the agreement are expected to be used for corporate development purposes and other general corporate purposes. The offering is made pursuant to the Company’s shelf registration statement on Form S-3, as amended, which became effective on September 26, 2003, as supplemented by a prospectus supplement, dated July 27, 2006, filed with the SEC pursuant to Rule 424(b) under the Securities Act of 1933, as amended. The Company has not issued any stock under the Sales Agency Financing Agreement through

December 31, 2006.

Centennial Energy Holdings, Inc. Centennial has three revolving credit agreements with various banks and institutions totaling $437.9 million with certain provisions allowing for increased borrowings. These credit agreements support Centennial's $400 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2006. Under the Centennial commercial paper program, $97.1 million was outstanding at December 31, 2006. 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 (supported by Centennial credit agreements). One of these credit agreements is for $400 million, which includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on August 26, 2010. Another agreement is for $17.9 million and expires on April 30, 2007. The third agreement is an uncommitted line for $20 million, and may be terminated by the bank at any time. As of December 31, 2006, $41.9 million of letters of credit were outstanding, as discussed in Item 8 - Note 20, of which $25.9 million reduced amounts available under these agreements.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $550 million. Under the terms of the master shelf agreement, $539.5 million was outstanding at December 31, 2006. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009. To meet potential future financing needs, Centennial may pursue other financing arrangements, including private and/or public financing.

Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Minor fluctuations in Centennial's credit ratings have not limited, nor would they be expected to limit, Centennial's ability to access the capital markets. In the event of a minor downgrade, Centennial may experience 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, it may need to borrow under its committed bank lines.

Prior to the maturity of the Centennial credit agreements, Centennial expects that it will 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, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent (for the $400 million credit agreement) and 60 percent (for the $17.9 million credit agreement and the master shelf agreement). Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1 (for the $400 million credit agreement), 2.25 to 1 (for the $17.9 million credit agreement) and 1.75 to 1 (for the master shelf agreement). Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2006. 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, $80.0 million was outstanding at December 31, 2006. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2008.

In order to borrow under its uncommitted long-term master shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2006. 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
In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging from approximately two to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

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 - Notes 9 and 20. At December 31, 2006, the Company’s commitments under these obligations were as follows:

	2007	2008	2009	2010	2011	Thereafter	Total
				(In millions)			
Long-term debt	$ 84.0	$ 161.8	$ 73.3	$ 104.4	$ 92.7	$ 738.4	$ 1,254.6
Estimated interest payments*	66.6	61.3	54.1	50.4	42.5	228.5	503.4
Operating leases	18.1	14.3	12.0	10.7	8.6	35.6	99.3
Purchase commitments	693.4**	99.7	81.8	62.3	55.9	225.5	1,218.6
	$ 862.1	$ 337.1	$ 221.2	$ 227.8	$ 199.7	$ 1,228.0	$ 3,075.9

* Estimated interest payments are calculated based on the applicable rates and payment dates.
** Includes expenditures related to the anticipated third quarter acquisition of Cascade. For more information, see Item 8 - Note 22.

EFFECTS OF INFLATION
Inflation did not have a significant effect on the Company's operations in 2006, 2005 or 2004.

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 on 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; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would 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.

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.

The fair value of the hedging instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas or oil production quantities are settled, 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 proceeds the Company receives for its natural gas and oil production also are generally based on market prices.

The following table summarizes hedge agreements entered into by Fidelity as of December 31, 2006. These agreements call for Fidelity to receive fixed prices and pay variable prices.

	(Forward notional amount and fair value in thousands)	
	Weighted Average Fixed Price	Forward Notional Amount

	(Per MMBtu)	(In MMBtu's)	Fair Value
Natural gas swap agreements maturing in 2007	$7.69	9,125	$14,845

	Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Amount (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2007	$7.87/$10.74	10,123	$17,256

The following table summarizes hedge agreements entered into by Fidelity as of December 31, 2005. These agreements call for Fidelity to receive fixed prices and pay variable prices.

	(Forward notional amount and fair value in thousands)		
	Weighted Average Fixed Price (Per MMBtu)	Forward Notional Amount (In MMBtu's)	Fair Value
Natural gas swap agreements maturing in 2006	$7.04	7,185	$(18,303)
	Weighted Average Floor/Ceiling Price (Per MMBtu)	Forward Notional Amount (In MMBtu's)	Fair Value
Natural gas collar agreements maturing in 2006	$7.50/$9.20	16,380	$(21,874)
	Weighted Average Floor/Ceiling Price (Per barrel)	Forward Notional Amount (In barrels)	Fair Value
Oil collar agreements maturing in 2006	$50.56/$60.84	329	$(1,834)

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 also has 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. At December 31, 2006 and 2005, the Company had no outstanding interest rate hedges.

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, 2006.

	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$84.0	$161.8	$73.3	$ 7.3	$66.9	$738.4	$1,131.7	$1,126.0
Weighted average interest rate	8.1%	4.5%	6.1%	6.8%	7.1%	5.7%	5.8%	-
Variable rate	-	-	-	$97.1	$25.8	-	$ 122.9	$ 121.4
Weighted average interest rate	-	-	-	5.4%	5.4%	-	5.4%	-

Foreign currency risk

MDU Brasil's equity method investments in the Brazilian Transmission Lines are exposed to market risks from changes in foreign currency exchange rates between the U.S. dollar and the Brazilian Real. For further information, see Item 8 - Note 4.

At December 31, 2006 and 2005, the Company had no outstanding foreign currency hedges.

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 is 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, 2006. 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, 2006.

Management's assessment of the Company's internal control over financial reporting as of December 31, 2006, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ Terry D. Hildestad	/s/ Vernon A. Raile
Terry D. Hildestad	Vernon A. Raile
President and Chief Executive Officer	Executive Vice President, Treasurer 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. and subsidiaries (the "Company") as of December 31, 2006 and 2005, 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, 2006. Our audits also included the financial statement schedule for each of the three years in the period ended December 31, 2006, listed in the Index at Item 15. These consolidated financial statements and the financial statement schedule 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, 2006 and 2005, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2006, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedule for each of the three years in the period ended December 31, 2006, when considered in relation to the consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Notes 1 and 17 to the consolidated financial statements, the Company adopted SFAS No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* effective as of December 31, 2006.

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, 2006, 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 14, 2007, 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 14, 2007

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. and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2006, 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, 2006, 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, 2006, 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, 2006, and our report dated February 14, 2007, expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company's adoption of SFAS No. 158 *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* effective as of December 31, 2006.

/s/ Deloitte & Touche LLP

DELOITTE & TOUCHE LLP
Minneapolis, Minnesota
February 14, 2007

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31,		**2006**		2005		2004
		(In thousands, except per share amounts)				
Operating revenues:						
Electric, natural gas distribution and pipeline and energy services	**$**	**889,286**	$	950,324	$	773,771
Construction services, natural gas and oil production, construction materials and mining, independent power production and other		**3,181,398**		2,502,107		1,942,421
		4,070,684		3,452,431		2,716,192
Operating expenses:						
Fuel and purchased power		**71,776**		63,591		64,618
Purchased natural gas sold		**268,981**		329,190		249,924
Operation and maintenance:						
Electric, natural gas distribution and pipeline and energy services		**183,992**		155,323		154,826
Construction services, natural gas and oil production, construction materials and mining, independent power production and other		**2,611,530**		2,106,855		1,614,053
Depreciation, depletion and amortization		**271,583**		228,386		208,514
Taxes, other than income		**130,586**		119,929		96,583
Asset impairments (Note 1)		**---**		---		2,076
		3,538,448		3,003,274		2,390,594
Operating income		**532,236**		449,157		325,598
Earnings from equity method investments		**10,838**		20,192		25,053
Other income		**12,186**		7,403		12,711
Interest expense		**72,095**		54,384		57,137
Income before income taxes		**483,165**		422,368		306,225
Income taxes		**165,248**		146,510		94,296
Income from continuing operations		**317,917**		275,858		211,929
Loss from discontinued operations, net of tax (Note 2)		**(2,160)**		(775)		(4,862)
Net income		**315,757**		275,083		207,067
Dividends on preferred stocks		**685**		685		685
Earnings on common stock	**$**	**315,072**	$	274,398	$	206,382
Earnings per common share - basic:						
Earnings before discontinued operations	**$**	**1.76**	$	1.54	$	1.21
Discontinued operations, net of tax		**(.01)**		---		(.03)
Earnings per common share - basic	**$**	**1.75**	$	1.54	$	1.18
Earnings per common share - diluted:						
Earnings before discontinued operations	**$**	**1.75**	$	1.53	$	1.20
Discontinued operations, net of tax		**(.01)**		---		(.03)

Earnings per common share - diluted	**$**	**1.74**	$	1.53	$	1.17
Dividends per common share	**$**	**.5234**	$	.4934	$	.4667
Weighted average common shares outstanding - basic		**180,234**		178,365		174,723
Weighted average common shares outstanding - diluted		**181,392**		179,490		176,117

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

MDU RESOURCES GROUP, INC.
CONSOLIDATED BALANCE SHEETS

December 31,		**2006**		2005
	(In thousands, except shares and per share amounts)			
ASSETS				
Current assets:				
Cash and cash equivalents	**$**	**74,921**	$	107,435
Receivables, net		**624,682**		601,062
Inventories		**204,440**		171,213
Deferred income taxes		**---**		9,062
Prepayments and other current assets		**81,284**		39,066
Current assets held for sale (Note 3)		**8,408**		5,358
		993,735		933,196
Investments		**155,111**		98,217
Property, plant and equipment (Note 1)		**4,729,163**		4,203,520
Less accumulated depreciation, depletion and amortization		**1,735,812**		1,524,211
		2,993,351		2,679,309
Deferred charges and other assets:				
Goodwill (Note 5)		**228,334**		219,429
Other intangible assets, net (Note 5)		**23,492**		11,851
Other		**103,840**		89,579
Noncurrent assets held for sale (Note 3)		**405,611**		391,981
		761,277		712,840
	$	**4,903,474**	$	4,423,562
LIABILITIES AND STOCKHOLDERS' EQUITY				
Current liabilities:				
Long-term debt due within one year	**$**	**84,034**	$	101,758
Accounts payable		**300,050**		259,057
Taxes payable		**54,290**		49,262
Deferred income taxes		**5,969**		---
Dividends payable		**24,606**		22,951
Other accrued liabilities		**184,013**		184,385
Current liabilities held for sale (Note 3)		**1,000**		11,515
		653,962		628,928
Long-term debt (Note 9)		**1,170,548**		1,104,752
Deferred credits and other liabilities:				
Deferred income taxes		**546,602**		499,375
Other liabilities		**336,916**		270,180
Noncurrent liabilities held for sale (Note 3)		**30,533**		28,705
		914,051		798,260

Commitments and contingencies (Notes 17, 19 and 20)				
Stockholders' equity:				
Preferred stocks (Note 11)		**15,000**		15,000
Common stockholders' equity:				
Common stock (Note 12)				
Authorized - 250,000,000 shares, $1.00 par value				
Issued - 181,557,543 shares in 2006 and 120,262,786 shares in 2005		**181,558**		120,263
Other paid-in capital		**874,253**		909,006
Retained earnings		**1,104,210**		884,795
Accumulated other comprehensive loss		**(6,482)**		(33,816)
Treasury stock at cost - 538,921 shares in 2006 and 359,281 in 2005		**(3,626)**		(3,626)
Total common stockholders' equity		**2,149,913**		1,876,622
Total stockholders' equity		**2,164,913**		1,891,622
	$	**4,903,474**	$	4,423,562

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

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF COMMON STOCKHOLDERS' EQUITY

Years ended December 31, 2006, 2005 and 2004

	Common Stock		Other		Accumulated Other	Treasury Stock		
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Loss	Shares	Amount	Total
				(In thousands, except shares)				
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)
Tax benefit on stock-based compensation	---	---	6,222	---	---	---	---	6,222
Issuance of common stock	4,869,433	4,869	99,440	---	---	---	---	104,309
Balance at December 31, 2004	118,586,065	118,586	863,449	699,095	(11,491)	(359,281)	(3,626)	1,666,013
Comprehensive								

income:								
Net income	---	---	---	275,083	---	---	---	275,083
Other comprehensive income (loss), net of tax -								
Net unrealized loss on derivative instruments qualifying as hedges	---	---	---	---	(21,800)	---	---	(21,800)
Minimum pension liability adjustment	---	---	---	---	574	---	---	574
Foreign currency translation adjustment	---	---	---	---	(1,099)	---	---	(1,099)
Total comprehensive income	---	---	---	---	---	---	---	252,758
Dividends on preferred stocks	---	---	---	(685)	---	---	---	(685)
Dividends on common stock	---	---	---	(88,698)	---	---	---	(88,698)
Tax benefit on stock-based compensation	---	---	5,487	---	---	---	---	5,487
Issuance of common stock	1,676,721	1,677	40,070	---	---	---	---	41,747
Balance at December 31, 2005	120,262,786	120,263	909,006	884,795	(33,816)	(359,281)	(3,626)	1,876,622
Comprehensive income:								
Net income	---	---	---	315,757	---	---	---	315,757
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	---	---	---	---	45,610	---	---	45,610
Minimum pension								

liability adjustment	---	---	---	---	1,761	---	---	1,761
Foreign currency translation adjustment	---	---	---	---	(1,585)	---	---	(1,585)
Total comprehensive income	---	---	---	---	---	---	---	361,543
SFAS No. 158 transition adjustment	---	---	---	---	(18,452)	---	---	(18,452)
Dividends on preferred stocks	---	---	---	(685)	---	---	---	(685)
Dividends on common stock	---	---	---	(95,657)	---	---	---	(95,657)
Tax benefit on stock-based compensation	---	---	2,524	---	---	---	---	2,524
Issuance of common stock (pre-split)	120,702	121	3,242	---	---	---	---	3,363
Three-for-two common stock split (Note 12)	60,191,744	60,192	(60,192)	---	---	(179,640)	---	---
Issuance of common stock (post-split)	982,311	982	19,673	---	---	---	---	20,655
Balance at December 31, 2006	**181,557,543**	**$ 181,558**	**$ 874,253**	**$ 1,104,210**	**$ (6,482)**	**(538,921)**	**$ (3,626)**	**$ 2,149,913**

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

MDU RESOURCES GROUP, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Years ended December 31,	**2006**	2005	2004
		(In thousands)	
Operating activities:			
Net income	$ **315,757**	$ 275,083	$ 207,067
Loss from discontinued operations, net of tax	**2,160**	775	4,862
Income from continuing operations	**317,917**	275,858	211,929
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	**271,583**	228,386	208,514
Earnings, net of distributions, from equity method investments	**(4,093)**	(14,385)	(22,261)
Deferred income taxes	**40,051**	30,300	33,200
Asset impairments	**---**	---	2,076
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(10,750)**	(114,922)	(62,427)
Inventories	**(29,736)**	(20,217)	(23,668)
Other current assets	**(10,183)**	418	9,663
Accounts payable	**29,919**	51,225	30,848
Other current liabilities	**33,734**	25,968	44,278
Other noncurrent changes	**22,139**	21,491	4,011
Net cash provided by continuing operations	**660,581**	484,122	436,163
Net cash used in discontinued operations	**(1,106)**	(883)	(3,092)
Net cash provided by operating activities	**659,475**	483,239	433,071
Investing activities:			
Capital expenditures	**(508,975)**	(510,825)	(337,627)
Acquisitions, net of cash acquired	**(126,313)**	(213,557)	(37,138)
Net proceeds from sale or disposition of property	**30,575**	40,554	20,518
Investments	**(59,202)**	1,833	(54,265)
Proceeds from sale of equity method investment	**---**	38,166	---
Proceeds from notes receivable	**---**	---	22,000
Net cash used in continuing operations	**(663,915)**	(643,829)	(386,512)
Net cash provided by (used in) discontinued operations	**3,689**	(81)	(61)
Net cash used in investing activities	**(660,226)**	(643,910)	(386,573)
Financing activities:			
Issuance of long-term debt	**356,352**	353,937	15,449
Repayment of long-term debt	**(315,486)**	(106,822)	(38,021)
Proceeds from issuance of common stock	**19,963**	9,165	70,129
Dividends paid	**(93,450)**	(87,551)	(81,019)
Tax benefit on stock-based compensation	**2,524**	---	---
Net cash provided by (used in) continuing operations	**(30,097)**	168,729	(33,462)
Net cash provided by discontinued operations	**---**	---	---
Net cash provided by (used in) financing activities	**(30,097)**	168,729	(33,462)
Effect of exchange rate changes on cash and cash equivalents	**(1,666)**	---	---

Increase (decrease) in cash and cash equivalents		**(32,514)**		8,058		13,036
Cash and cash equivalents - beginning of year		**107,435**		99,377		86,341
Cash and cash equivalents - end of year	**$**	**74,921**	$	107,435	$	99,377

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, construction 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. Construction 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 15. 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 4.

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. 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 6 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, 2006 and 2005, was $7.7 million and $8.0 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 $32.6 million and $24.7 million at December 31, 2006 and 2005, respectively. The remainder of natural gas in underground storage was included in other assets and was $44.2 million and $43.2 million at December 31, 2006 and 2005, respectively.

Inventories

Inventories, other than natural gas in underground storage for the Company’s regulated operations, consisted primarily of aggregates held for resale of $88.1 million and $78.1 million, materials and supplies of $54.1 million and $47.7 million, and other inventories of $29.6 million and $20.7 million, as of December 31, 2006 and 2005, respectively.

These inventories were stated at the lower of average cost or market value.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. 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 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 $8.3 million, $11.5 million and $6.2 million in 2006, 2005 and 2004, 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 aggregate reserves, 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 was as follows:

	2006	2005	Estimated Depreciable Life in Years
	(Dollars in thousands, as applicable)		
Regulated:			
Electric:			
Electric generation, distribution and transmission plant	**$ 703,838**	$ 670,771	4-50
Natural gas distribution:			
Natural gas distribution plant	**289,106**	277,288	4-45
Pipeline and energy services:			
Natural gas transmission, gathering and storage facilities	**384,354**	374,646	8-104
Nonregulated:			
Construction services:			
Land	**3,974**	2,533	---
Buildings and improvements	**11,288**	12,063	3-40
Machinery, vehicles and equipment	**70,687**	67,439	2-10
Other	**8,805**	8,075	3-10
Pipeline and energy services:			
Natural gas gathering and other facilities	**178,055**	146,662	3-20
Energy services	**187**	187	3-7
Natural gas and oil production:			
Natural gas and oil properties	**1,606,508**	1,280,960	*
Other	**29,737**	22,487	3-15
Construction materials and mining:			
Land	**95,294**	91,613	---
Buildings and improvements	**96,533**	87,550	1-30
Machinery, vehicles and equipment	**817,209**	738,568	1-30
Construction in progress	**23,968**	15,687	---
Aggregate reserves	**377,653**	377,008	**
Independent power production:			
Other	**2,057**	2,077	3-10
Other:			

Land		**3,079**	2,919	---
Other		**26,831**	24,987	3-40
Less accumulated depreciation, depletion and amortization		**1,735,812**	1,524,211	
Net property, plant and equipment	**$**	**2,993,351**	$ 2,679,309	

* *Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $1.38, $1.19 and $.98 for the years ended December 31, 2006, 2005 and 2004, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $164.0 million and $82.3 million were excluded from amortization at December 31, 2006 and 2005, respectively.*

** *Depleted on the units-of-production method based on recoverable aggregate reserves.*

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, 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 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 significant impairment losses were recorded in 2006 and 2005. 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. For more information on goodwill impairments and goodwill, see Notes 2 and 5.

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, plus 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, 2006 and 2005, 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, 2006, 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, 2006, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2006	2005	2004	2003 and prior
		(In thousands)			

Acquisition	$ 60,770	$ 23,547	$ 12,720	$ 2,515	$ 21,988
Development	85,631	64,973	13,770	5,279	1,609
Exploration	9,328	6,399	2,929	---	---
Capitalized interest	8,246	5,026	1,558	413	1,249
Total costs not subject to amortization	$ 163,975	$ 99,945	$ 30,977	$ 8,207	$ 24,846

Costs not subject to amortization as of December 31, 2006, consisted primarily of unevaluated leaseholds, drilling costs, seismic costs and capitalized interest associated primarily with CBNG in the Powder River Basin of Montana and Wyoming; oil and gas development in the Big Horn Basin of Wyoming; an exploration project in southern Texas; the Bakken Play in western North Dakota; the Red River B prospect in western South Dakota; 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 years and included in the amortization base as the properties are evaluated and/or developed.

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 reasonably assured. 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 properties 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 EITF No. 91-6 ratably over the terms of the related contract. Arrangements with multiple revenue-generating activities are recognized under EITF No. 00-21 with the multiple deliverables divided into separate units of accounting based on specific criteria and revenues of the arrangements allocated to the separate units based on their relative fair values. 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 $41.3 million and $52.3 million at December 31, 2006 and 2005, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs on uncompleted contracts of $93.0 million and $50.7 million at December 31, 2006 and 2005, 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 $81.8 million and $59.5 million at December 31, 2006 and 2005, 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 on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

Asset retirement obligations

The Company records 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 at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 10.

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 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $7.5 million at December 31, 2006, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $691,000 at December 31, 2005, 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 $750,000 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 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 the Brazilian Transmission Lines and its former investment in the Termoceara Generating Facility, as further discussed in Note 4, 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 are translated on a year-to-date basis using weighted average daily exchange rates. 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 would be recorded in income.

Common stock split

On May 11, 2006, the Company's Board of Directors approved a three-for-two common stock split. For more information on the common stock split, see Note 12.

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 year ended December 31, 2004, 54,000 shares, with an average exercise price of $17.13, attributable to the exercise of outstanding options were excluded from the calculation of diluted earnings per share because their effect was antidilutive. In 2006 and 2005, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury.

Stock-based compensation

On January 1, 2006, the Company adopted SFAS No. 123 (revised). This accounting standard revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) was adopted using the modified prospective method, recognizing compensation expense for all awards granted after the date of adoption of the standard and for the unvested portion of previously granted awards that remain outstanding at the date of adoption. In accordance with the modified prospective method, the Company’s consolidated financial statements for prior periods have not been restated to reflect, and do not include, the impact of SFAS No. 123 (revised).

On January 1, 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 accounted for stock options granted prior to January 1, 2003, under APB Opinion No. 25 and no compensation expense was recognized 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 following table illustrates the effect on earnings and earnings per common share for the years ended December 31, 2005 and 2004, 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:

		2005		2004
		(In thousands, except per share amounts)		
Earnings on common stock, as reported	$	274,398	$	206,382
Stock-based compensation expense included in reported earnings, net of related tax effects of $1,000 in 2005 and $12,000 in 2004		2		18
Total stock-based compensation expense determined under fair value method for all awards, net of related tax effects		(471)		(62)
Pro forma earnings on common stock	$	273,929	$	206,338
Earnings per common share - basic - as reported	$	1.54	$	1.18
Earnings per common share - basic - pro forma	$	1.54	$	1.18
Earnings per common share - diluted - as reported	$	1.53	$	1.17
Earnings per common share - diluted - pro forma	$	1.53	$	1.17

For more information on the Company's stock-based compensation, see Note 13.

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, as well as 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. 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,	**2006**	2005	2004
		(In thousands)	
Interest, net of amount capitalized	**$ 65,850**	$ 47,902	$ 50,236
Income taxes	**$ 105,317**	$ 106,771	$ 50,487

New accounting standards

SFAS No. 123 (revised) In December 2004, the FASB issued SFAS No. 123 (revised). This accounting standard revises SFAS No. 123 and requires entities to recognize compensation expense in an amount equal to the grant-date fair value of share-based payments granted to employees. SFAS No. 123 (revised) was effective for the Company on January 1, 2006. As of the required effective date, the Company applied SFAS No. 123 (revised) using the modified prospective method, recognizing 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. For more information on the adoption of SFAS No. 123 (revised), see Note 13.

EITF No. 04-6 In March 2005, the FASB ratified EITF No. 04-6. EITF No. 04-6 requires that stripping costs during the production phase of a mine be treated as a variable inventory production cost when incurred. EITF No. 04-6 was effective for the Company on January 1, 2006. The adoption of EITF No. 04-6 did not have a material effect on the Company’s financial position or results of operations.

FIN 48 In July 2006, the FASB issued FIN 48. FIN 48 clarifies the application of SFAS No. 109 by defining a criterion that an individual tax position must meet for any part of the benefit of that position to be recognized in an enterprise’s financial statements. The criterion allows for recognition in the financial statements of a tax position when it is more likely than not that the position will be sustained upon examination. FIN 48 was effective for the Company on January 1, 2007. The adoption of FIN 48 did not have a material effect on the Company’s financial position or results of operations.

SFAS No. 157 In September 2006, the FASB issued SFAS No. 157. SFAS No. 157 defines fair value, establishes a framework for measuring fair value and expands disclosures about fair value measurements. The standard applies under other accounting pronouncements that require or permit fair value measurements with certain exceptions. SFAS No. 157 is effective for the Company on January 1, 2008. The Company is evaluating the effects of the adoption of SFAS No. 157.

SFAS No. 158 In September 2006, the FASB issued SFAS No. 158. SFAS No. 158 requires an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its balance sheet and recognize changes in that funded status in the year in which the changes occur through comprehensive income. The standard also requires an employer to measure the funded status of the plan as of the date of its year-end balance sheet. SFAS No. 158 was effective for the Company as of December 31, 2006. For more information on the implementation of SFAS No. 158, see Note 17.

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 7.

The components of other comprehensive income (loss), and their related tax effects for the years ended December 31, 2006, 2005 and 2004, were as follows:

		2006		2005		2004
				(In thousands)		
Other comprehensive income (loss):						
Net unrealized gain (loss) on derivative instruments qualifying as hedges:						
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $12,359, $16,391 and $2,734 in 2006, 2005 and 2004, respectively	**$**	**19,743**	$	(26,167)	$	(4,367)
Less: Reclassification adjustment for loss on derivative instruments included in net income, net of tax of $16,194, $2,734 and $2,132 in 2006, 2005 and 2004, respectively		**(25,867)**		(4,367)		(3,335)
Net unrealized gain (loss) on derivative instruments qualifying as hedges		**45,610**		(21,800)		(1,032)
Minimum pension liability adjustment, net of tax of $1,122, $353 and $2,406 in 2006, 2005 and 2004, respectively		**1,761**		574		(3,782)
Foreign currency translation adjustment		**(1,585)**		(1,099)		852
Total other comprehensive income (loss)	**$**	**45,786**	$	(22,325)	$	(3,962)

The after-tax components of accumulated other comprehensive loss as of December 31, 2006, 2005 and 2004, were as follows:

		Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges		Pension Liability Adjustment		Foreign Currency Translation Adjustment		Total Accumulated Other Comprehensive Loss
				(In thousands)				
Balance at December 31, 2004	$	(4,367)	$	(8,225)	$	1,101	$	(11,491)
Balance at December 31, 2005	$	(26,167)	$	(7,651)	$	2	$	(33,816)
Balance at December 31, 2006	**$**	**19,443**	**$**	**(24,342)**	**$**	**(1,583)**	**$**	**(6,482)**

NOTE 2 - DISCONTINUED OPERATIONS

Innovatum, a component of the pipeline and energy services segment, specialized in cable and pipeline magnetization and location. During the third quarter of 2006, the Company initiated a plan to sell Innovatum within the next year because the Company has determined that Innovatum is a non-strategic asset. During the fourth quarter of 2006, the stock and a portion of the assets of Innovatum were sold and the Company expects to sell the remaining assets of Innovatum within one year of the initial plan to sell. The loss on disposal on the portion of Innovatum that has been sold was not material. The Company does not expect to have any involvement in the operations of Innovatum after the sale.

In accordance with SFAS No. 144, the Company's consolidated financial statements and accompanying notes for current and prior periods have been restated to present the results of operations of Innovatum as a discontinued operation. In addition, the assets and liabilities of Innovatum have been treated as held for sale, and as a result, no depreciation, depletion and amortization expense is recorded. In accordance with SFAS No. 142, the Company was required to test Innovatum, a reporting unit for goodwill impairment testing, for impairment at the time that the Company committed to the plan to sell. The fair value of Innovatum was estimated using the expected proceeds from the sale, which was estimated to be the current book value of the assets of Innovatum other than its goodwill. As a result, a goodwill impairment loss of $4.3 million (before tax) was recognized in the third quarter of 2006 and recorded as part of discontinued operations, net of tax, in the Consolidated Statements of Income. The remaining assets of Innovatum are recorded at fair value less estimated selling costs. The carrying amounts of the major assets and liabilities of Innovatum are included in Note 3.

Operating results related to Innovatum for the years ended December 31, 2006, 2005 and 2004, were as follows:

		2006		2005		2004
				(In thousands)		
Operating revenues	**$**	**1,827**	$	2,983	$	3,065
Loss from discontinued operations before income tax benefit		**(5,994)**		(1,506)		(5,184)
Income tax benefit		**3,834**		731		322
Loss from discontinued operations	**$**	**(2,160)**	$	(775)	$	(4,862)

The income tax benefit for the year ended December 31, 2006, is larger than the customary relationship between the income tax benefit and the loss before tax due to a capital loss tax benefit (which reflects the effect of the $4.3 million and $4.0 million goodwill impairments in 2006 and 2004, respectively) resulting from the sale of the Innovatum stock.

NOTE 3 - ASSETS HELD FOR SALE

During the fourth quarter of 2006, the Company initiated a plan to sell certain of the domestic assets of Centennial Resources, which largely comprise the independent power production segment. The plan to sell was based on the increased market demand for independent power production assets, combined with the Company's desire to efficiently fund future capital needs. The assets and liabilities of these operations have been treated as held for sale and, in accordance with SFAS No. 144, the Company's consolidated balance sheets and accompanying notes for current and prior periods have been restated to present the assets as held for sale. At the time that the assets are classified as held for sale, depreciation, depletion and amortization expense is no longer recorded. The results of operations of these assets will continue to be shown in continuing operations in the Company's financial statements as the Company intends to have significant continuing involvement in the form of continuing current operation and maintenance agreements after the sale.

The carrying amounts of the major assets and liabilities related to the domestic independent power production assets held for sale, as well as the major assets and liabilities related to Innovatum, as discussed in Note 2, at December 31, 2006 and 2005, were as follows:

	2006	2005
	(In thousands)	
Receivables, net	**$ 6,103**	$ 2,897
Inventories	**490**	988
Other current assets	**1,815**	1,473
Total current assets held for sale	**$ 8,408**	$ 5,358
Net property, plant and equipment	**$ 389,750**	$ 370,584
Goodwill	**7,131**	11,436
Other intangible assets, net	**6,473**	7,208
Other assets	**2,257**	2,753
Total noncurrent assets held for sale	**$ 405,611**	$ 391,981
Accounts payable	**$ 331**	$ 9,964
Taxes payable	**---**	1,271
Other current liabilities	**669**	280
Total current liabilities held for sale	**$ 1,000**	$ 11,515
Deferred income taxes	**$ 27,956**	$ 26,801
Other liabilities	**2,577**	1,904
Total noncurrent liabilities held for sale	**$ 30,533**	$ 28,705

NOTE 4 - EQUITY METHOD INVESTMENTS

The Company's equity method investments at December 31, 2006, include Carib Power, Hartwell and the Brazilian Transmission Lines.

In February 2004, Centennial International acquired 49.99 percent of Carib Power. Carib Power, through a wholly owned subsidiary, owns a 225-MW natural gas-fired electric generating facility 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 agreement. The functional currency for the Trinity Generating Facility is the U.S. dollar. On December 29, 2006, the Company entered into a purchase agreement to sell its interest in Carib Power. Closing is expected to occur in the first quarter of 2007.

In September 2004, Centennial Resources, through indirect wholly owned subsidiaries, acquired a 50-percent ownership interest in Hartwell, which owns a 310-MW natural gas-fired electric generating facility near Hartwell, Georgia. The Hartwell Generating Facility sells its output under a power purchase agreement with Oglethorpe that expires in May 2019. Oglethorpe reimburses the Hartwell Generating Facility for actual costs of fuel required to operate the plant. 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 August 16, 2006, MDU Brasil acquired ownership interests in companies owning three electric transmission lines. The interests involve the ENTE (13.3-percent ownership interest), ERTE (13.3-percent ownership interest) and ECTE (25-percent ownership interest) electric transmission lines, which are primarily in northeastern and southern Brazil. The contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments and have between 24 and 26 years remaining under the contracts. Alusa, Brascan and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. Alusa is the operating partner for the transmission lines. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In June 2005, the Company completed the sale of its 49 percent interest in MPX to Petrobras, the Brazilian state-controlled energy company. The Company realized a gain of $15.6 million from the sale in the second quarter of 2005. In 2005, the Termoceara Generating Facility was accounted for as an asset held for sale and, as a result, no depreciation, depletion and amortization expense was recorded in 2005.

The functional currency for the Termoceara Generating Facility was the Brazilian Real. The electric power sales contract with Petrobras contained an embedded derivative, which derived its value from an annual adjustment factor, which largely indexed the contract capacity payments to the U.S. dollar. The Company's 49 percent share of the gain from the change in fair value of the embedded derivative in the electric power sales contract for the year ended December 31, 2004, was $2.5 million (after tax). The Company's 49 percent share of the foreign currency gain resulting from an increase in value of the Brazilian Real versus the U.S. dollar for the year ended December 31, 2004, was $1.9 million (after tax).

At December 31, 2006 and 2005, the Company’s equity method investments had total assets of $583.6 million and $231.9 million, respectively, and long-term debt of $321.5 million and $154.8 million, respectively. The Company’s investment in its equity method investments was approximately $102.0 million and $41.8 million, including undistributed earnings of $8.5 million and $3.5 million, at December 31, 2006 and 2005, respectively.

NOTE 5 - GOODWILL AND OTHER INTANGIBLE ASSETS

The changes in the carrying amount of goodwill for the year ended December 31, 2006, were as follows:

	Balance as of January 1, 2006	Goodwill Acquired During the Year*	Balance as of December 31, 2006
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	80,970	5,972	86,942
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	133,264	2,933	136,197
Independent power production	4,036	---	4,036
Other	---	---	---
Total	$ 219,429	$ 8,905	$ 228,334

* *Includes purchase price adjustments that were not material related to acquisitions in a prior period.*

The changes in the carrying amount of goodwill for the year ended December 31, 2005, were as follows:

	Balance as of January 1, 2005	Goodwill Acquired During the Year*	Balance as of December 31, 2005
		(In thousands)	
Electric	$ ---	$ ---	$ ---
Natural gas distribution	---	---	---
Construction services	62,632	18,338	80,970
Pipeline and energy services	1,159	---	1,159
Natural gas and oil production	---	---	---
Construction materials and mining	120,452	12,812	133,264
Independent power production	4,064	(28)	4,036
Other	---	---	---
Total	$ 188,307	$ 31,122	$ 219,429

* *Includes purchase price adjustments that were not material related to acquisitions in a prior period.*

Other intangible assets at December 31, 2006 and 2005, were as follows:

		2006		2005
		(In thousands)		
Amortizable intangible assets:				
Acquired contracts	**$**	**10,287**	$	5,484
Accumulated amortization		**(5,936)**		(3,847)
		4,351		1,637
Noncompete agreements		**12,886**		11,784
Accumulated amortization		**(8,540)**		(8,557)
		4,346		3,227
Other		**18,092**		7,561
Accumulated amortization		**(3,297)**		(1,098)
		14,795		6,463
Unamortizable intangible assets		**---**		524
Total	**$**	**23,492**	$	11,851

The unamortizable intangible assets at December 31, 2005, were recognized in accordance with SFAS No. 87, which required 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.

Amortization expense for amortizable intangible assets that are not held for sale for the years ended December 31, 2006, 2005 and 2004, was $4.4 million, $3.7 million and $1.9 million, respectively. Estimated amortization expense for amortizable intangible assets not held for sale is $5.0 million in 2007, $4.2 million in 2008, $3.2 million in 2009, $2.6 million in 2010, $1.6 million in 2011 and $6.9 million thereafter.

NOTE 6 - REGULATORY ASSETS AND LIABILITIES

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

		2006		2005
		(In thousands)		
Regulatory assets:				
Deferred income taxes	**$**	**35,978**	$	38,757
Pension and postretirement benefits		**19,075**		453
Plant costs		**13,254**		13,122
Long-term debt refinancing costs		**11,232**		3,160
Natural gas costs recoverable through rate adjustments		**---**		691
Other		**7,230**		6,066
Total regulatory assets		**86,769**		62,249
Regulatory liabilities:				
Plant removal and decommissioning costs		**85,087**		78,280
Deferred income taxes		**18,019**		10,298
Taxes refundable to customers		**14,229**		14,966
Natural gas costs refundable through rate adjustments		**7,516**		---
Liabilities for regulatory matters		**1,568**		7,405
Other		**2,611**		4,830
Total regulatory liabilities		**129,030**		115,779
Net regulatory position	**$**	**(42,261)**	$	(53,530)

As of December 31, 2006, 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 1 to 16 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 7 - 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 fair value. Changes in the derivative instrument’s fair value are recognized currently in earnings unless specific hedge accounting criteria are met. 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; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would 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, 2006, the Company had no outstanding foreign currency or interest rate hedges.

At December 31, 2006, 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.

The fair value of the hedging instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss). At the date the natural gas or oil production quantities are settled, 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 proceeds the Company receives for its natural gas and oil production are also generally based on market prices.

In the second quarter of 2006, Fidelity’s oil collar agreements became ineffective and no longer qualified for hedge accounting. The oil hedges became ineffective as the physical price received no longer correlated to the hedge price due to the widening of regional basis differentials on the price of the physical production received. The ineffectiveness related to these collar agreements resulted in a loss of approximately $138,000 (before tax) for the year ended December 31, 2006, that was recorded in operation and maintenance expense. The ineffective collar agreements had expired by December 31, 2006. The amount of hedge ineffectiveness on Fidelity's remaining hedges was immaterial for the year ended December 31, 2006. For the years ended December 31, 2005 and 2004, the amount of hedge ineffectiveness was immaterial.

For the years ended December 31, 2006, 2005 and 2004, Fidelity did not exclude any components of the derivative instruments' gain or loss from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such 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, 2006, 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. The Company estimates that over the next 12 months, net gains of approximately $19.7 million (after tax) 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 8 - 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 assets at December 31, 2006, and current liabilities at December 31, 2005. 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:

	2006		2005	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 1,254,582**	**$ 1,247,439**	$ 1,206,510	$ 1,219,347
Natural gas and oil price swap and collar agreements	**$ 32,101**	**$ 32,101**	$ (42,011)	$ (42,011)

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 9 - LONG-TERM DEBT AND INDENTURE PROVISIONS

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

	2006	2005
	(In thousands)	
First mortgage bonds and notes:		
Secured Medium-Term Notes, Series A, at a weighted average rate of 6.91%, due on dates ranging from April 1, 2007 to April 1, 2012	**$ 27,000**	$ 95,000
Senior Notes, 5.98%, due December 15, 2033	**30,000**	30,000

Total first mortgage bonds and notes		**57,000**		125,000
Senior notes at a weighted average rate of 5.73%, due on dates ranging from May 4, 2007 to July 1, 2019		**964,500**		815,000
Commercial paper at a weighted average rate of 5.42%, supported by revolving credit agreements		**122,850**		260,000
Term credit agreements at a weighted average rate of 6.31%, due on dates ranging from January 1, 2007 to August 24, 2026		**110,290**		6,623
Discount		**(58)**		(113)
Total long-term debt		**1,254,582**		1,206,510
Less current maturities		**84,034**		101,758
Net long-term debt	**$**	**1,170,548**	$	1,104,752

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2006, aggregate $84.0 million in 2007; $161.8 million in 2008; $73.3 million in 2009; $104.4 million in 2010; $92.7 million in 2011 and $738.4 million thereafter.

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants, all of which the Company and its subsidiaries were in compliance with at December 31, 2006.

MDU Resources Group, Inc.
The Company has a revolving credit agreement with various banks totaling $125 million (with provision for an increase, at the option of the Company on stated conditions and upon regulatory approval, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement at December 31, 2006 and 2005. The credit agreement supports the Company's $100 million commercial paper program. Under the Company's commercial paper program, $25.8 million and $60.0 million were outstanding at December 31, 2006 and 2005, respectively. The commercial paper borrowings are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings (supported by the credit agreement, which expires in June 2011).

In order to borrow under the Company's credit agreement, the Company must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Also included is a covenant that does not permit the ratio of the Company's earnings before interest, taxes, depreciation and amortization to interest expense (determined with respect to the Company alone, excluding its subsidiaries), for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1. Other covenants include restrictions on the sale of certain assets and on the making of certain investments. The Company was in compliance with these covenants and met the required conditions at December 31, 2006. 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.

The Company's issuance of first mortgage debt is subject to certain restrictions imposed under the terms and conditions of its 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, 2006, the Company could have issued approximately $461 million of additional first mortgage bonds.

Approximately $459.6 million in net book value of the Company's net electric and natural gas distribution properties at December 31, 2006, with certain exceptions, are subject to the lien of the Mortgage and to the junior lien of the Indenture.

Centennial Energy Holdings, Inc.
Centennial has three revolving credit agreements with various banks and institutions totaling $437.9 million with certain provisions allowing for increased borrowings. These credit agreements support Centennial’s $400 million commercial paper program. There were no outstanding borrowings under the Centennial credit agreements at December 31, 2006 and 2005. Under the Centennial commercial paper program, $97.1 million and $200.0 million were outstanding at December 31, 2006 and 2005, 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 (supported by Centennial credit agreements). One of these credit agreements is for $400 million, which includes a provision for an increase, at the option of Centennial on stated conditions, up to a maximum of $450 million and expires on August 26, 2010. Another agreement is for $17.9 million and expires on April 30, 2007. The third agreement is an uncommitted line for $20 million and may be terminated by the bank at any time. As of December 31, 2006, $41.9 million of letters of credit were outstanding, as discussed in Note 20, of which $25.9 million reduced amounts available under these agreements.

Centennial has an uncommitted long-term master shelf agreement that allows for borrowings of up to $550 million. Under the terms of the master shelf agreement, $539.5 million and $447.5 million were outstanding at December 31, 2006 and 2005, respectively. The ability to request additional borrowings under this master shelf agreement expires on May 8, 2009. To meet potential future financing needs, Centennial may pursue other financing arrangements, including private and/or public financing.

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, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent (for the $400 million credit agreement) and 60 percent (for the $17.9 million credit agreement and the master shelf agreement). Also included is a covenant that does not permit the ratio of Centennial’s earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 2.5 to 1 (for the $400 million credit agreement), 2.25 to 1 (for the $17.9 million credit agreement) and 1.75 to 1 (for the master shelf agreement). Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments. Centennial and such subsidiaries were in compliance with these covenants and met the required conditions at December 31, 2006. 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, $80.0 million and $55.0 million were outstanding at December 31, 2006 and 2005, respectively. The ability to request additional borrowings under this master shelf agreement expires on December 20, 2008.

In order to borrow under its uncommitted long-term master shelf agreement, Williston Basin must be in compliance with the applicable covenants and certain other conditions, including covenants not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments. Williston Basin was in compliance with these covenants and met the required conditions at December 31, 2006. In the event Williston Basin does not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

NOTE 10 - ASSET RETIREMENT OBLIGATIONS

In accordance with SFAS No. 143, the Company records 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 Company adopted FIN 47 on December 31, 2005. The Company recorded obligations related to special handling and disposal of hazardous materials at certain electric generating and distribution facilities, natural gas distribution and transmission facilities, and buildings. Upon adoption of FIN 47, the Company recorded an additional discounted liability of $1.7 million and a regulatory asset of $1.5 million and increased net property, plant and equipment by $151,000. There was no impact on net income; therefore pro forma presentation amounts assuming retroactive application of the accounting change on net income are not necessary.

A reconciliation of the Company's liability, which is included in other liabilities, for the years ended December 31 was as follows:

		2006		2005
		(In thousands)		
Balance at beginning of year	**$**	**42,857**	$	36,752
Liabilities incurred		**4,878**		3,786
Liabilities acquired		**1,118**		1,138
Liabilities settled		**(2,963)**		(3,328)
Accretion expense		**3,093**		2,059
Revisions in estimates		**6,321**		740
Liabilities recorded upon adoption of FIN 47		**---**		1,663
Other		**875**		47
Balance at end of year	**$**	**56,179**	$	42,857

The following reconciliation of the Company’s liability for the years ended December 31 includes the pro forma effects of the adoption of FIN 47 for 2005.

		2005
		(In thousands)
Balance at beginning of year	$	38,326
Liabilities incurred		3,786
Liabilities acquired		1,138
Liabilities settled		(3,328)
Accretion expense		2,059
Revisions in estimates		740
Other		136
Balance at end of year	$	42,857

The Company believes that any expenses under SFAS No. 143 and FIN 47 as they relate to regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2006 and 2005, was $5.5 million and $5.1 million, respectively.

NOTE 11 - PREFERRED STOCKS
Preferred stocks at December 31 were as follows:

	2006	2005
	(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 per share and $102 per share, 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 bylaws 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 12 - COMMON STOCK
On May 11, 2006, 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 July 26, 2006, to common stockholders of record on July 12, 2006. Certain common stock information appearing in the accompanying consolidated financial statements has been restated in accordance with accounting principles generally

accepted in the United States of America to give retroactive effect to the stock split. Additionally, preference share purchase rights have been appropriately adjusted to reflect the effects of the split.

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 four-ninths 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 four-ninths of one one-thousandth of a share of 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 $.00444 per right, at the Company's option at any time until any acquiring person has acquired 15 percent or more of the Company's common stock.

The 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 K-Plan is partially funded with the Company's common stock. From January 1, 2004, through June 30, 2006, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded by the purchase of shares of common stock on the open market. Beginning July 1, 2006, shares of authorized but unissued common stock were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2006, there were 20.9 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

NOTE 13 - STOCK-BASED COMPENSATION

On January 1, 2006, the Company adopted SFAS No. 123 (revised) and on January 1, 2003, adopted SFAS No. 123. For a discussion of the adoption of SFAS No. 123 (revised) and SFAS No. 123, see Note 1.

The Company has several stock-based compensation plans and is authorized to grant options, restricted stock and stock for up to 17.1 million shares of common stock and has granted options, restricted stock and stock of 6.7 million shares through December 31, 2006. The Company generally issues new shares of common stock to satisfy stock option exercises, restricted stock, stock and performance share awards.

Total stock-based compensation expense for the year ended December 31, 2006, was $3.5 million, net of income taxes of $2.2 million, including $349,000, net of income taxes of $223,000 related to stock option awards.

As of December 31, 2006, total remaining unrecognized compensation expense related to stock-based compensation was approximately $4.7 million (before income taxes) which will be amortized over a weighted average period of 1.7 years.

Stock options

The Company has stock option plans for directors, key employees and employees. The Company has not granted stock options since 2003. 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 the date of grant and three years after the date of grant, respectively, and expire 10 years after the date of grant.

The fair value of each option outstanding was estimated on the date of grant using the Black-Scholes option-pricing model.

A summary of the status of the stock option plans at December 31, 2006, 2005 and 2004, and changes during the years then ended were as follows:

	2006			2005			2004		
	Shares		Weighted Average Exercise Price	Shares		Weighted Average Exercise Price	Shares		Weighted Average Exercise Price
Balance at beginning of year	**2,786,973**	**$**	**12.99**	3,842,526	$	12.86	6,273,684	$	12.73
Forfeited	**(108,109)**		**13.08**	(171,828)		13.53	(574,413)		13.09
Exercised	**(367,318)**		**12.21**	(883,725)		12.32	(1,856,745)		12.33
Balance at end of year	**2,311,546**		**13.11**	2,786,973		12.99	3,842,526		12.86
Exercisable at end of year	**1,244,369**	**$**	**12.67**	1,640,285	$	12.57	2,550,335	$	12.49

Summarized information about stock options outstanding and exercisable as of December 31, 2006, was as follows:

	Options Outstanding						Options Exercisable				
Range of Exercisable Prices	Number Outstanding	Remaining Contractual Life in Years		Weighted Average Exercise Price		Aggregate Intrinsic Value (000's)	Number Exercisable		Weighted Average Exercise Price		Aggregate Intrinsic Value (000's)
$ 7.28 - 8.00	5,062	.5	$	7.28	$	93	5,062	$	7.28	$	93
8.01 - 11.00	250,807	1.4		9.60		4,023	247,915		9.60		3,977
11.01 - 14.00	1,815,448	4.2		13.19		22,602	908,762		13.19		11,315
14.01 - 17.13	240,229	4.2		16.30		2,244	82,630		16.50		755
Balance at end of year	2,311,546	3.9	$	13.11	$	28,962	1,244,369	$	12.67	$	16,140

The aggregate intrinsic value in the preceding table represents the total intrinsic value (before income taxes), based on the Company’s stock price on December 31, 2006, which would have been received by the option holders had all option holders exercised their options as of that date.

The weighted average remaining contractual life of options exercisable was 3.6 years at December 31, 2006.

The Company received cash of $4.5 million from the exercise of stock options for the year ended December 31, 2006. The aggregate intrinsic value of options exercised during the year ended December 31, 2006, was $4.4 million.

Restricted stock awards

Prior to 2002, the Company granted restricted stock awards under a long-term incentive plan. The restricted stock awards granted vest at various times ranging from one year to nine years from the 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 grant-date fair value is the market price of the Company’s stock on the grant date.

A summary of the status of the restricted stock awards for the year ended December 31, 2006, was as follows:

	Number of	Weighted Average Grant-Date

	Shares		Fair Value
Nonvested at beginning of period	130,764	$	10.63
Vested	(77,106)		8.82
Forfeited	(21,541)		13.22
Nonvested at end of period	32,117	$	13.22

The fair value of restricted stock awards that vested during the year ended December 31, 2006, was $1.8 million.

Stock awards
Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 50,627 shares with a fair value of $1.3 million issued under this plan during the year ended December 31, 2006.

Performance share awards
Since 2003, key employees of the Company have been awarded performance share awards each year. 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 outstanding at December 31, 2006, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2004	2004-2006	278,600
February 2005	2005-2007	258,256
February 2006	2006-2008	201,828

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value. The grant-date fair value of performance share awards granted during the years ended December 31, 2006, 2005 and 2004, was $25.22, $18.36 and $15.81, per share, respectively. The grant-date fair value for the performance shares granted in 2006 was determined by Monte Carlo simulation using a blended volatility term structure in the range of 17.65 to 18.79 percent comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure in the range of 4.66 to 4.79 percent based on U.S. Treasury security rates in effect as of the grant date. In addition, the mean over all simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was $1.37 per target share. The grant-date fair value for the performance shares issued in 2005 and 2004 was equal to the market value of the common stock on the grant date. The fair value of performance share awards that vested during the year ended December 31, 2006, was $2.2 million.

A summary of the status of the performance share awards for the year ended December 31, 2006, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	634,275	$	16.31
Granted	216,970		24.87
Additional performance shares earned	14,522		11.14
Vested	(95,792)		11.14
Forfeited	(31,291)		19.23
Nonvested at end of period	738,684	$	19.27

NOTE 14 - INCOME TAXES

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

	2006	2005	2004
		(In thousands)	
United States	**$ 479,017**	$ 408,531	$ 286,411
Foreign	**4,148**	13,837	19,814
Income before income taxes	**$ 483,165**	$ 422,368	$ 306,225

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

	2006	2005	2004
		(In thousands)	
Current:			
Federal	**$ 106,063**	$ 95,746	$ 48,101
State	**18,998**	20,557	12,201
Foreign	**136**	(93)	794
	125,197	116,210	61,096
Deferred:			
Income taxes -			
Federal	**35,893**	25,806	28,516
State	**4,563**	4,994	5,484
Foreign	**---**	---	(208)
Investment tax credit	**(405)**	(500)	(592)
	40,051	30,300	33,200
Total income tax expense	**$ 165,248**	$ 146,510	$ 94,296

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

	2006	2005
	(In thousands)	
Deferred tax assets:		
Accrued pension costs	**$ 43,433**	$ 22,000
Regulatory matters	**35,978**	38,757
Asset retirement obligations	**14,789**	13,017
Deferred compensation	**13,286**	13,057
Natural gas and oil price swap and collar agreements	**---**	16,375
Other	**43,818**	34,622
Total deferred tax assets	**151,304**	137,828
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	**445,315**	438,836
Basis differences on natural gas and oil producing properties	**204,288**	159,077
Regulatory matters	**18,019**	10,298
Natural gas and oil price swap and collar agreements	**12,359**	---
Other	**23,894**	19,930
Total deferred tax liabilities	**703,875**	628,141
Net deferred income tax liability	**$ (552,571)**	$ (490,313)

As of December 31, 2006 and 2005, 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, 2005, to December 31, 2006, to deferred income tax expense:

		2006
		(In thousands)
Change in net deferred income tax liability from the preceding table	$	**62,258**
Deferred taxes associated with other comprehensive income		**(29,675)**
Deferred taxes associated with SFAS No. 158 transition adjustment		**11,826**
Deferred taxes associated with acquisitions		**(1,696)**
Other		**(2,662)**
Deferred income tax expense for the period	$	**40,051**

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,		**2006**			2005			2004	
		Amount	%		Amount	%		Amount	%
					(Dollars in thousands)				
Computed tax at federal statutory rate	$	**169,108**	**35.0**	$	147,829	35.0	$	107,179	35.0
Increases (reductions) resulting from:									
State income taxes, net of federal income tax benefit		**18,218**	**3.8**		15,501	3.7		11,515	3.8
Depletion allowance		**(4,784)**	**(1.0)**		(4,381)	(1.0)		(3,418)	(1.1)
Renewable electricity production credit		**(4,423)**	**(.9)**		(4,087)	(1.0)		(3,404)	(1.1)
Resolution of tax matters		**(4,252)**	**(.9)**		---	---		(8,818)	(2.9)
Domestic production activities deduction		**(2,324)**	**(.5)**		(2,219)	(.5)		---	---
Foreign operations		**136**	**---**		(4,225)	(1.0)		(5,743)	(1.9)
Other items		**(6,431)**	**(1.3)**		(1,908)	(.5)		(3,015)	(1.0)
Total income tax expense	$	**165,248**	**34.2**	$	146,510	34.7	$	94,296	30.8

The Company considers earnings (including the gain from the sale of 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, 2006, were approximately $38 million. The amount of unrecognized deferred tax liability associated with the undistributed earnings was approximately $11 million.

NOTE 15 - BUSINESS SEGMENT DATA

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The 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 transmission and natural resource-based projects.

The electric segment generates, transmits and distributes electricity in Montana, North Dakota, South Dakota and Wyoming. The natural gas distribution segment distributes natural gas in those states as well as in western Minnesota. These operations also supply related value-added products and services.

The construction services segment specializes in electrical line construction, pipeline construction, inside electrical wiring and cabling, as well as external lighting and traffic signalization and mechanical and fire protection services 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.

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 and Mid-Continent regions 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, liquid asphalt and other value-added products. It also performs integrated construction services. The construction materials and mining segment operates in the central, southern and western United States and Alaska and Hawaii.

The independent power production segment owns, builds and operates electric generating facilities in the United States and has domestic and international investments including transmission and 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.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer 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.

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:

		2006		2005		2004
				(In thousands)		
External operating revenues:						
Electric	**$**	**187,301**	$	181,238	$	178,803
Natural gas distribution		**351,988**		384,199		316,120
Pipeline and energy services		**349,997**		384,887		278,848
		889,286		950,324		773,771
Construction services		**987,079**		686,734		425,250
Natural gas and oil production		**251,153**		163,539		152,486
Construction materials and mining		**1,877,021**		1,603,326		1,321,626
Independent power production		**66,145**		48,508		43,059
Other		**---**		---		---
		3,181,398		2,502,107		1,942,421
Total external operating revenues	**$**	**4,070,684**	$	3,452,431	$	2,716,192

Intersegment operating revenues:			
Electric	**$ ---**	$ ---	$ ---
Natural gas distribution	**---**	---	---
Construction services	**503**	391	1,571
Pipeline and energy services	**93,723**	92,424	75,316
Natural gas and oil production	**232,799**	275,828	190,354
Construction materials and mining	**---**	1,284	535
Independent power production	**---**	---	---
Other	**8,117**	6,038	4,423
Intersegment eliminations	**(335,142)**	(375,965)	(272,199)
Total intersegment operating revenues	**$ ---**	$ ---	$ ---
Depreciation, depletion and amortization:			
Electric	**$ 21,396**	$ 20,818	$ 20,199
Natural gas distribution	**9,776**	9,534	9,329
Construction services	**15,449**	13,459	11,113
Pipeline and energy services	**13,288**	12,513	17,548
Natural gas and oil production	**106,768**	84,754	70,823
Construction materials and mining	**88,723**	77,988	69,644
Independent power production	**15,182**	8,990	9,587
Other	**1,001**	330	271
Total depreciation, depletion and amortization	**$ 271,583**	$ 228,386	$ 208,514
Interest expense:			
Electric	**$ 6,493**	$ 7,553	$ 9,116
Natural gas distribution	**3,885**	3,973	4,292
Construction services	**6,295**	4,177	3,442
Pipeline and energy services	**8,094**	8,132	8,962
Natural gas and oil production	**9,864**	7,550	7,552
Construction materials and mining	**25,943**	21,365	20,646
Independent power production	**11,734**	2,260	4,354
Other	**41**	(399)	(70)
Intersegment eliminations	**(254)**	(227)	(1,157)
Total interest expense	**$ 72,095**	$ 54,384	$ 57,137
Income taxes:			
Electric	**$ 7,403**	$ 8,308	$ 4,303
Natural gas distribution	**2,108**	2,240	(3,883)
Construction services	**16,497**	9,693	(3,345)
Pipeline and energy services	**18,938**	13,735	7,767
Natural gas and oil production	**78,960**	82,428	61,261
Construction materials and mining	**46,245**	29,244	26,674
Independent power production	**(4,850)**	483	1,249
Other	**(53)**	379	270
Total income taxes	**$ 165,248**	$ 146,510	$ 94,296
Earnings on common stock:			

Electric	**$**	**14,401**	$	13,940	$	12,790
Natural gas distribution		**5,680**		3,515		2,182
Construction services		**27,851**		14,558		(5,650)
Pipeline and energy services		**32,126**		22,867		13,806
Natural gas and oil production		**145,657**		141,625		110,779
Construction materials and mining		**85,702**		55,040		50,707
Independent power production		**4,513**		22,921		26,309
Other		**1,302**		707		321
Earnings on common stock before loss from discontinued operations		**317,232**		275,173		211,244
Loss from discontinued operations, net of tax		**(2,160)**		(775)		(4,862)
Total earnings on common stock	**$**	**315,072**	$	274,398	$	206,382
Capital expenditures:						
Electric	**$**	**39,055**	$	27,036	$	18,767
Natural gas distribution		**15,398**		17,224		17,384
Construction services		**31,354**		50,900		8,470
Pipeline and energy services		**42,749**		36,399		38,282
Natural gas and oil production		**328,979**		329,773		111,506
Construction materials and mining		**141,088**		161,977		133,080
Independent power production		**33,128**		135,778		76,246
Other		**2,088**		11,913		4,215
Net proceeds from sale or disposition of property		**(30,575)**		(40,554)		(20,518)
Total net capital expenditures	**$**	**603,264**	$	730,446	$	387,432
Identifiable assets:						
Electric*	**$**	**353,593**	$	330,327	$	323,819
Natural gas distribution*		**264,102**		271,653		252,582
Construction services		**401,832**		351,654		230,955
Pipeline and energy services		**474,424**		466,961		447,302
Natural gas and oil production		**1,173,797**		898,883		685,610
Construction materials and mining		**1,562,868**		1,498,338		1,345,547
Independent power production		**527,358**		483,900		349,752
Other**		**145,500**		121,846		97,954
Total identifiable assets	**$**	**4,903,474**	$	4,423,562	$	3,733,521
Property, plant and equipment:						
Electric*	**$**	**703,838**	$	670,771	$	650,902
Natural gas distribution*		**289,106**		277,288		264,496
Construction services		**94,754**		90,110		82,600
Pipeline and energy services		**562,596**		521,495		491,137
Natural gas and oil production		**1,636,245**		1,303,447		982,625
Construction materials and mining		**1,410,657**		1,310,426		1,190,468
Independent power production		**2,057**		2,077		1,643
Other		**29,910**		27,906		17,335
Less accumulated depreciation, depletion and amortization		**1,735,812**		1,524,211		1,345,172
Net property, plant and equipment	**$**	**2,993,351**	$	2,679,309	$	2,336,034

* *Includes allocations of common utility property.*

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

The pipeline and energy services segment recognized a loss from discontinued operations, net of tax, of $2.1 million, $775,000 and $4.9 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Excluding the loss from discontinued operations, and the asset impairment of $1.3 million (after tax) in 2004, at pipeline and energy services, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings (loss) from construction services, natural gas and oil production, construction materials and mining, independent power production, and other are all from nonregulated operations. Capital expenditures for 2006, 2005 and 2004 include noncash transactions, including the issuance of the Company's equity securities in connection with acquisitions. The noncash transactions were immaterial in 2006, $46.5 million in 2005 and $33.1 million in 2004.

NOTE 16 - ACQUISITIONS

In 2006, the Company acquired a construction services business in Nevada, natural gas and oil production properties in Wyoming, construction materials and mining businesses in California and Washington, and a natural gas-fired electric generating facility in California at the independent power production segment, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2006, consisting of the Company's common stock and cash, was $133.1 million.

In 2005, the Company acquired construction services businesses in Nevada, natural gas and oil production properties in southern Texas and construction materials and mining businesses in Idaho, Iowa and Oregon, none of which was material. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions acquired prior to 2005, consisting of the Company's common stock and cash, was $245.2 million.

In 2004, the Company acquired a number of businesses including construction materials and mining businesses in Hawaii, Idaho, Iowa and Minnesota and an independent power production operating and development company in Colorado, none of which was material. The total purchase consideration for these businesses and purchase price 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 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. On certain of the above acquisitions made in 2006, final fair market values are pending the completion of the review of the relevant assets, liabilities and issues identified as of the acquisition date. The results of operations of the acquired businesses and properties 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 17 - EMPLOYEE BENEFIT PLANS

The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Effective January 1, 2006, the Company discontinued defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005. These employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans. 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 year ended December 31, 2006, and amounts recognized in the Consolidated Balance Sheets at December 31, 2006, were as follows:

	Pension Benefits 2006	Other Postretirement Benefits 2006
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	**$ 303,393**	**$ 69,811**
Service cost	**8,901**	**2,015**
Interest cost	**16,056**	**3,633**
Plan participants' contributions	**---**	**1,533**
Amendments	**---**	**---**
Actuarial gain	**(14,363)**	**(4,019)**
Benefits paid	**(15,589)**	**(5,249)**
Benefit obligation at end of year	**298,398**	**67,724**
Change in plan assets:		
Fair value of plan assets at beginning of year	**245,328**	**52,448**
Actual gain on plan assets	**27,047**	**6,440**
Employer contribution	**2,489**	**3,575**
Plan participants' contributions	**---**	**1,533**
Benefits paid	**(15,589)**	**(5,249)**
Fair value of plan assets at end of year	**259,275**	**58,747**
Funded status - under	**$ (39,123)**	**$ (8,977)**
Amounts recognized in the Consolidated Balance Sheets at December 31:		
Prepaid benefit cost (noncurrent)	**$ 4,368**	**$ ---**
Accrued benefit liability (current)	**---**	**(364)**
Accrued benefit liability (noncurrent)	**(43,491)**	**(8,613)**
Net amount recognized	**$ (39,123)**	**$ (8,977)**
Amounts recognized in accumulated other comprehensive loss consist of:		
Actuarial (gain) loss	**$ 30,415**	**$ (13,718)**
Prior service cost	**5,948**	**648**
Transition obligation	**---**	**12,753**
Total	**$ 36,363**	**$ (317)**

Changes in benefit obligation and plan assets for the year ended December 31, 2005, and amounts recognized in the Consolidated Balance Sheets at December 31, 2005, were as follows:

	Pension Benefits 2005	Other Postretirement Benefits 2005
	(In thousands)	
Change in benefit obligation:		
Benefit obligation at beginning of year	$ 284,756	$ 75,491
Service cost	8,336	1,719
Interest cost	16,617	3,784
Plan participants' contributions	---	1,386
Amendments	451	743
Actuarial (gain) loss	7,046	(8,924)

Benefits paid		(13,813)		(4,388)
Benefit obligation at end of year		303,393		69,811
Change in plan assets:				
Fair value of plan assets at beginning of year		239,522		50,978
Actual gain on plan assets		16,805		1,419
Employer contribution		2,814		3,053
Plan participants' contributions		---		1,386
Benefits paid		(13,813)		(4,388)
Fair value of plan assets at end of year		245,328		52,448
Funded status - under		(58,065)		(17,363)
Unrecognized actuarial (gain) loss		55,097		(7,621)
Unrecognized prior service cost		6,861		694
Unrecognized net transition obligation (asset)		(3)		14,878
Prepaid (accrued) benefit cost	$	3,890	$	(9,412)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Prepaid benefit cost	$	18,690	$	787
Accrued benefit liability		(14,800)		(10,199)
Additional minimum liability		(1,434)		---
Intangible asset		524		---
Accumulated other comprehensive income		910		---
Net amount recognized	$	3,890	$	(9,412)

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

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets is amortized on a straight-line basis over the expected average remaining service lives of active participants. The market-related value of assets is determined using a five-year average of assets. Unrecognized postretirement net transition obligation is amortized over a 20-year period ending 2012.

The accumulated benefit obligation for the defined benefit pension plans reflected above was $245.6 million and $244.3 million at December 31, 2006 and 2005, 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, 2006 and 2005, were as follows:

		2006		2005
	(In thousands)			
Projected benefit obligation	**$**	**187,638**	$	190,877
Accumulated benefit obligation	**$**	**151,850**	$	151,399
Fair value of plan assets	**$**	**148,261**	$	139,108

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the year ended December 31, 2006, were as follows:

	Pension Benefits	Other Postretirement Benefits
	2006	**2006**
	(In thousands)	
Components of net periodic benefit cost:		

Service cost	$	**8,901**	$	**2,015**
Interest cost		**16,056**		**3,633**
Expected return on assets		**(19,913)**		**(4,119)**
Amortization of prior service cost		**913**		**46**
Recognized net actuarial (gain) loss		**1,699**		**(243)**
Amortization of net transition obligation (asset)		**(3)**		**2,125**
Net periodic benefit cost, including amount capitalized		**7,653**		**3,457**
Less amount capitalized		**689**		**261**
Net periodic benefit cost		**6,964**		**3,196**
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive loss:				
Net gain		**(22,983)**		**(6,340)**
Amortization of actuarial gain (loss)		**(1,699)**		**243**
Amortization of prior service cost		**(913)**		**(46)**
Amortization of net transition (obligation) asset		**3**		**(2,125)**
Total recognized in accumulated other comprehensive loss		**(25,592)**		**(8,268)**
Total recognized in net periodic benefit cost and accumulated other comprehensive loss	$	**(18,628)**	$	**(5,072)**

Components of net periodic benefit cost for the Company's pension and other postretirement benefit plans for the years ended December 31, 2005 and 2004, were as follows:

		Pension Benefits				Other Postretirement Benefits		
		2005		2004		2005		2004
				(In thousands)				
Components of net periodic benefit cost:								
Service cost	$	8,336	$	7,667	$	1,719	$	1,826
Interest cost		16,617		15,903		3,784		4,312
Expected return on assets		(19,947)		(20,375)		(4,005)		(3,943)
Amortization of prior service cost		1,025		1,121		45		144
Recognized net actuarial (gain) loss		1,385		480		(549)		(233)
Amortization of net transition obligation (asset)		(45)		(250)		2,126		2,151
Net periodic benefit cost, including amount capitalized		7,371		4,546		3,120		4,257
Less amount capitalized		730		409		313		440
Net periodic benefit cost	$	6,641	$	4,137	$	2,807	$	3,817

The estimated net loss and prior service cost for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2007 are $806,000 and $834,000, respectively. The estimated net gain, prior service cost and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2007 are $691,000, $45,000 and $2.1 million, respectively.

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

	Pension Benefits	Other Postretirement Benefits

	2006	2005	**2006**	2005
Discount rate	**5.75%**	5.50%	**5.75%**	5.50%
Rate of compensation increase	**4.30%**	4.30%	**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	
	2006	2005	**2006**	2005
Discount rate	**5.50%**	5.75%	**5.50%**	5.75%
Expected return on plan assets	**8.50%**	8.50%	**7.50%**	7.50%
Rate of compensation increase	**4.30%**	4.70%	**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:

	2006	2005
Health care trend rate assumed for next year	**6.0%-9.0%**	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	**1999-2014**	1999-2014

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, 2006:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$(93)	$ (828)
Effect on postretirement benefit obligation	$387	$(7,858)

The Company's defined benefit pension plans' asset allocation at December 31, 2006 and 2005, and weighted average targeted asset allocations at December 31, 2006, were as follows:

	Percentage	Weighted Average Targeted Asset

Asset Category	of Plan Assets **2006**	2005	Allocation Percentage **2006**
Equity securities	**69%**	74%	**70%**
Fixed income securities	**27**	21	**30***
Other	**4**	5	**---**
Total	**100%**	100%	**100%**

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

The Company's pension assets are managed by 11 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, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. 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, 2006 and 2005, and weighted average targeted asset allocation at December 31, 2006, were as follows:

Asset Category	Percentage of Plan Assets **2006**	2005	Weighted Average Targeted Asset Allocation Percentage **2006**
Equity securities	**70%**	70%	**70%**
Fixed income securities	**27**	28	**30***
Other	**3**	2	**---**
Total	**100%**	100%	**100%**

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

The Company expects to contribute approximately $4.5 million to its defined benefit pension plans and approximately $3.0 million to its postretirement benefit plans in 2007.

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

Years	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2007	$ 13,840	$ 4,126
2008	14,077	4,196
2009	14,590	4,313
2010	15,307	4,471
2011	15,788	4,676
2012-2016	91,453	26,112

The following Medicare Part D subsidies are expected: $606,000 in 2007; $639,000 in 2008; $677,000 in 2009; $712,000 in 2010; $747,000 in 2011; and $4.4 million during the years 2012 through 2016.

In addition to company-sponsored plans, certain employees are covered under multi-employer pension plans administered by a union. Amounts contributed to the multi-employer plans were $57.6 million, $39.6 million and $28.2 million in 2006, 2005 and 2004, 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, 2006, consisted of cash equivalents, fixed income securities, equity securities, and life insurance carried on plan participants, which is payable upon the employee's death. The Company's net periodic benefit cost for this plan was $7.5 million, $7.4 million and $7.5 million in 2006, 2005 and 2004, respectively. The total projected obligation for this plan was $69.5 million and $64.9 million at December 31, 2006 and 2005, respectively. The accumulated benefit obligation for this plan was $57.4 million and $55.0 million at December 31, 2006 and 2005, respectively. A discount rate of 5.75 percent and 5.50 percent at December 31, 2006 and 2005, respectively, and a rate of compensation increase of 4.25 percent at both December 31, 2006 and 2005, were used to determine benefit obligations.

A discount rate of 5.50 percent and 5.75 percent at December 31, 2006 and 2005, respectively, and a rate of compensation increase of 4.25 percent and 4.75 percent at December 31, 2006 and 2005, respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plan, as appropriate, are expected to aggregate $2.8 million in 2007; $3.1 million in 2008; $3.3 million in 2009; $3.9 million in 2010; $4.4 million in 2011; and $28.4 million for the years 2012 through 2016.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $17.3 million in 2006, $17.0 million in 2005 and $13.8 million in 2004. The costs incurred in each year reflect additional participants as a result of business acquisitions.

SFAS No. 158 became effective for the Company as of December 31, 2006, as discussed in Note 1. The following tables illustrate the incremental effect of applying SFAS No. 158 on individual line items in the Consolidated Balance Sheets at December 31, 2006:

	Before Application of SFAS No. 158	Transition Adjustment	After Application of SFAS No. 158
		(In Thousands)	
Other assets (noncurrent)	$ 97,637	$ 6,203	$ 103,840
Other accrued liabilities (current)	183,649	364	184,013
Other liabilities (noncurrent)	300,799	36,117	336,916
Deferred income taxes	534,776	11,826	546,602
Accumulated other comprehensive income (loss)	11,970	(18,452)	(6,482)
Total stockholders' equity	2,183,365	(18,452)	2,164,913

NOTE 18 - 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:

	2006		2005	
	(In thousands)			
Big Stone Station:				
Utility plant in service	**$**	**55,659**	$	56,305
Less accumulated depreciation		**38,881**		38,011
	$	**16,778**	$	18,294
Coyote Station:				
Utility plant in service	**$**	**125,950**	$	125,007
Less accumulated depreciation		**78,056**		76,563
	$	**47,894**	$	48,444

NOTE 19 - REGULATORY MATTERS AND REVENUES SUBJECT TO REFUND

In September 2004, Great Plains filed a natural gas rate application with the MNPUC requesting a revenue increase of $1.4 million annually, or approximately 4 percent. An interim increase of $1.4 million annually was effective January 10, 2005, subject to refund. The final order in the amount of $481,000 annually, or 1.3 percent, was issued on May 1, 2006. A compliance filing was submitted to the MNPUC on August 11, 2006, and a resolution of outstanding compliance issues was submitted on December 26, 2006. On January 11, 2007, the MNPUC approved Great Plains' December 26, 2006, filing reflecting the increase of $481,000. Final rates were implemented in January 2007 and interim rate refunds will be issued to customers in March 2007. Great Plains has adequately provided a liability for the revenue 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 April 2005, the FERC issued its Order on Compliance Filing and Motion for Refunds. In this Order, the FERC approved Williston Basin's refund rates and established rates to be effective April 19, 2005. Williston Basin made its compliance filing complying with the requirements of this Order regarding rates and issued refunds totaling approximately $18.5 million to its customers in May 2005. As a result of the Order, Williston Basin recorded a $5.0 million (after tax) benefit in the second quarter of 2005 from the resolution of the rate proceeding which included the reversal of a portion of the liability it had previously established for this regulatory proceeding. In June 2005, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision dated July 2003 and its Order on Rehearing dated May 2004 concerning determinations associated with cost of service and volumes used in allocating costs and designing rates. Oral argument was held on October 20, 2006, regarding those matters. On December 22, 2006, the D.C. Appeals Court issued its Opinion which dismissed Williston Basin's appeal of certain issues addressed by the FERC Order described previously. The D.C. Appeals Court found that Williston Basin had failed to satisfy the jurisdictional requirements of the Natural Gas Act when it appealed the issues. As a result, Williston Basin reversed the remaining liability it had previously established for this proceeding and recorded a $4.1 million (after tax) benefit in 2006.

In May 2004, the FERC remanded issues regarding certain service and annual demand quantity restrictions to an ALJ for resolution. In November 2005, the FERC issued an Order on Initial Decision affirming the ALJ's Initial Decision regarding the service and annual demand quantity restrictions. On April 20, 2006, the FERC issued an Order on Rehearing denying Williston Basin's Request for Rehearing of the FERC's November 2005 Order. On April 25, 2006, Williston Basin appealed to the D.C. Appeals Court certain issues addressed by the FERC's Order on Initial Decision dated November 2005 and its Order on Rehearing issued April 20, 2006, concerning the service and annual demand quantity restrictions. Those matters are pending resolution by the D.C. Appeals Court.

NOTE 20 - COMMITMENTS AND CONTINGENCIES
Litigation
Royalties Case In June 1997, Grynberg, acting on behalf of the United States, filed suit under the Federal False Claims Act against Williston Basin and Montana-Dakota. He also filed more than 70 similar suits against natural gas transmission companies and producers, gatherers and processors of natural gas. Grynberg 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. All cases were consolidated in Wyoming Federal District Court.

In June 2004, following preliminary discovery, Williston Basin and Montana-Dakota joined with other defendants and filed a Motion to Dismiss on the ground 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 was heard in March 2005 by the Special Master appointed by the Wyoming Federal District Court. The Special Master, in his Written Report dated May 2005, recommended that the lawsuit be dismissed against certain defendants, including Williston Basin and Montana-Dakota.

On October 20, 2006, the Wyoming Federal District Court adopted and modified the Special Master's Written Report and ordered that the actions against Williston Basin and Montana-Dakota be dismissed. Grynberg filed a Notice of Appeal of the decision to the U.S. Tenth Circuit Court of Appeals on November 16, 2006.

In the event the Wyoming Federal District Court's decision is overturned and Grynberg's actions are reinstated, 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.

Coalbed Natural Gas Operations 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 CBNG 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 January 2007 by a number of environmental organizations, including the NPRC and the Montana Environmental Information Center, as well as the TRWUA and the Northern Cheyenne Tribe. Portions of three of the lawsuits have been transferred to the Wyoming Federal District Court. The lawsuits involve allegations that Fidelity and/or various government agencies are in violation of state and/or federal law, including the Clean Water Act, the NEPA, the Federal Land Management Policy Act, the NHPA, the Montana State Constitution, the Montana Environmental Policy Act and the Montana Water Quality Act. The suits that remain extant include a variety of claims that state and federal government agencies violated various environmental laws that impose procedural and substantive requirements. The lawsuits seek injunctive relief, invalidation of various permits and unspecified damages. Fidelity has intervened or moved to intervene in three lawsuits filed by other gas producers which challenge the adoption of rules by the BER related to management of water associated with CBNG production. The state of Wyoming has filed a similar suit and Fidelity has also moved to intervene in that action.

In suits filed in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted that the BLM violated NEPA and other federal laws when approving the 2003 EIS analyzing CBNG development in southeastern Montana. The Montana Federal District Court, in February 2005, entered a ruling finding that the 2003 EIS was inadequate. The Montana Federal District Court later entered an order that would have allowed limited CBNG development in the Powder River Basin in Montana pending the BLM's preparation of a SEIS. The plaintiffs appealed the decision to the Ninth Circuit because the Montana Federal District Court declined to enter an injunction enjoining all development pending completion of the SEIS. The Montana Federal District Court also declined to enter an injunction pending the appeal. In May 2005, the Ninth Circuit granted the request of the NPRC and the Northern Cheyenne Tribe and, pending appeal or further order from the Ninth Circuit, enjoined the BLM from approving any new CBNG development projects in the Montana Powder River Basin. The Ninth Circuit also enjoined Fidelity from drilling any additional federally permitted wells associated with its Montana Coal Creek Project and from constructing infrastructure to produce and transport CBNG from the Coal Creek Project's existing federal wells. The matter has been fully briefed and argued before the Ninth Circuit and the parties are awaiting a decision of the court. On December 13, 2006, the BLM issued a draft SEIS, which the Company is studying. The final SEIS is scheduled for release in the summer of 2007.

In related actions in the Montana Federal District Court, the NPRC and the Northern Cheyenne Tribe asserted, among other things, that the actions of the BLM in approving Fidelity's applications for permits and the plan of development for the Badger Hills Project in Montana did not comply with applicable federal laws, including the NHPA and the NEPA. In June 2005, the Montana Federal District Court issued orders in these cases enjoining operations on Fidelity's Badger Hills Project pending the BLM's consultation with the Northern Cheyenne Tribe as to satisfaction of the applicable requirements of the NHPA and a further environmental analysis under the NEPA. Fidelity sought and obtained stays of the injunctive relief from the Montana Federal District Court and production from Fidelity’s Badger Hills Project continues. In September 2005, the Montana Federal District Court entered an Order based on a stipulation between the parties to the NPRC action that production from existing wells in Fidelity’s Badger Hills Project may continue pending preparation of a revised environmental analysis. In November 2005, the Montana Federal District Court entered an Order dismissing the Northern Cheyenne Tribe lawsuit based on the parties’ stipulation that production from existing wells in Fidelity’s Badger Hills Project could continue pending consultation with the Tribe under the NHPA. In December 2005, Fidelity filed a Notice of Appeal of the NPRC lawsuit to the Ninth Circuit in connection with the Montana Federal District Court’s decision insofar as it found the BLM’s approval of Fidelity’s applications did not comply with applicable law.

In May 2005, the NPRC and other petitioners filed a petition with the BER to promulgate rules related to the management of water produced in association with CBNG operations. Thereafter, the BER initiated related rulemaking proceedings to consider rules that would, if promulgated, require re-injection of water produced in connection with CBNG operations, treatment of such water in the event re-injection is not feasible and amend the non-degradation policy in connection with CBNG development to include additional limitations on factors deemed harmful, thereby restricting discharges even further than under the previous standards. On March 23, 2006, the BER issued its decision on the NPRC’s rulemaking petition. The BER rejected the proposed requirement of re-injection of water produced in connection with CBNG and deferred action on the proposed treatment requirement. The BER adopted the proposed amendment to the non-degradation policy. While it is possible the BER’s ruling could have an adverse impact on Fidelity’s operations, Fidelity believes that two five-year water discharge permits issued by the Montana DEQ in February 2006 should, assuming normal operating conditions, allow Fidelity to continue its existing CBNG operations at least through the expiration of the permits in March 2011. However, these permits are now under challenge in Montana state court by the Northern Cheyenne Tribe. Specifically, on April 3, 2006, the Northern Cheyenne Tribe filed a complaint in the District Court of Big Horn County against the Montana DEQ seeking to set aside the two permits. The Northern Cheyenne Tribe asserted that the Montana DEQ issued the permits in violation of various federal and state environmental laws. In particular, the Northern Cheyenne Tribe claimed the agency violated the Clean Water Act and the Montana Water Quality Act by failing to include in the permits conditions requiring application of the best practicable control technology currently available and by ignoring the BER’s recently adopted amendment to the non-degradation policy. In addition, the Northern Cheyenne Tribe claimed that the actions of the Montana DEQ violated the Montana State Constitution’s guarantee of a clean and healthful environment, that the Montana DEQ’s related environmental assessment was invalid, that the Montana DEQ was required, but failed, to prepare an EIS and that it failed to consider other alternatives to the issuance of the permits. Fidelity, the NPRC and the TRWUA have been granted leave to intervene in this proceeding. Fidelity has asserted that the Northern Cheyenne Tribe’s complaint should be dismissed with prejudice, that Fidelity’s discharge of water pursuant to its two permits is its primary means for managing CBNG produced water and that, if its permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

In a related proceeding, on July 25, 2006, Fidelity filed a motion to intervene in a lawsuit filed in the District Court of Big Horn County by other producers. The lawsuit challenges the BER's 2006 rulemaking, which amended the nondegradation policy, as well as the BER's 2003 rulemaking procedure which first set numeric limits for certain parameters contained in water produced in connection with CBNG operations. Fidelity's motion for intervention was granted on August 1, 2006.

Similarly, industry members have filed two lawsuits, and the state of Wyoming has filed one lawsuit, in Wyoming Federal District Court. These lawsuits challenge the EPA's failure to timely disapprove the 2006 rules. All three Wyoming lawsuits were consolidated on September 22, 2006. Fidelity has moved to intervene in these consolidated cases.

Fidelity will continue to vigorously defend its interests in all CBNG-related lawsuits and related actions in which it is involved, including the Ninth Circuit injunction and the proceedings challenging its water permits. In those cases where damage claims have been asserted, Fidelity is unable to quantify the damages sought and will be unable to do so until after the completion of discovery. If the plaintiffs are successful in these lawsuits, the ultimate outcome of the actions could have a material effect on Fidelity's existing CBNG operations and/or the future development of this resource in the affected regions.

Electric Operations Montana-Dakota joined with two electric generators in appealing a September 2003 finding by the ND Health Department that it 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 ND 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 were stayed pending conclusion of the periodic review of sulfur dioxide emissions in the state.

In September 2005, the ND Health Department issued its final periodic review decision based on its August 2005 final air quality modeling report. The ND Health Department concluded there are no violations of the sulfur dioxide increment in North Dakota. In March 2006, the DRC filed a complaint in Colorado Federal District Court seeking to force the EPA to declare that the increment had been violated based on earlier modeling conducted by the EPA. The EPA is defending against the DRC claim and it has filed a motion to dismiss the case. The Colorado Federal District Court has not yet ruled on the motion.

Montana-Dakota expects the EPA to initiate a rulemaking proceeding to formally approve the conclusions contained in the September 2005 ND Health Department decision and the August 2005 final report. Once concluded, this rulemaking should result in a revision to the North Dakota SIP that, in turn, should allow for the dismissal of the case in Burleigh County District Court referenced above.

On November 20, 2006, the Sierra Club sent a notice of intent to file a citizen suit in federal court under the Clean Air Act to the co-owners, including Montana-Dakota, of the Big Stone Station. The suit would seek injunctive relief and monetary penalties based on the Sierra Club's claim that three projects conducted at the Big Stone Station between 1995 and 2005 were modifications of a major source and that the Big Stone Station failed to obtain a prevention of significant deterioration permit, conduct best available control technology analyses, and comply with other regulatory requirements for those projects. The South Dakota Department of Environment and Natural Resources reviewed and approved the three projects and the co-owners of the Big Stone Station believe that the Sierra Club's claims are without merit. The Big Stone Station co-owners intend to vigorously defend their interests if the suit is filed.

Natural Gas Storage Williston Basin filed suit in Montana Federal District Court on January 27, 2006, seeking to recover unspecified damages from Anadarko and its wholly owned subsidiary, Howell, and to enjoin Anadarko and Howell's present and future production from specified wells in and near the EBSR, one of Williston Basin's natural gas storage reservoirs. Based on relevant information, including reservoir and well pressure data, Williston Basin believes that the EBSR pressures have decreased. By December 31, 2006, Williston Basin estimated approximately 6.5 Bcf of storage gas had been diverted as a result of Anadarko and Howell's drilling and production activities in areas within and near the boundaries of the EBSR, and that storage gas losses from the EBSR are continuing. Williston Basin is seeking not only to recover damages for the storage gas that has been and is being diverted, but to prevent further loss of gas from the EBSR. The Montana Federal District Court entered an Order on July 14, 2006, dismissing the case for lack of subject matter jurisdiction. Williston Basin filed a Notice of Appeal to the Ninth Circuit on July 31, 2006.

In related litigation, Howell filed suit in Wyoming state district court against Williston Basin asserting that it is entitled to produce any gas that might escape from the EBSR. On August 30, 2006, Williston Basin moved for a preliminary injunction to halt Anadarko and Howell's production in and near the EBSR. A district-court-appointed special master conducted a hearing on the motion in mid-December 2006, and recommended denial of the motion on February 15, 2007. The district court is expected to rule on the special master's recommendation in the first quarter of 2007.

In light of the actions of Howell and Anadarko, Williston Basin installed additional compression at the site in order to maintain deliverability into the transmission system. While installation of the additional compression has provided temporary relief, Williston Basin believes that the adverse physical and operational effects occasioned by the continued loss of storage gas, if left unchecked, could threaten the operation and viability of the EBSR, impair Williston Basin's ability to comply with the EBSR certificated operating requirements mandated by the FERC and adversely affect Williston Basin's ability to meet its contractual storage and transportation service commitments to customers. Williston Basin intends to vigorously defend its rights and interests in these proceedings, to assess further avenues for recovery through the regulatory process at the FERC, and to pursue the recovery of any and all economic losses it may have suffered. Williston Basin cannot predict the ultimate outcome of this proceeding.

The Company also is 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

Portland Harbor Site In December 2000, MBI was named by the EPA as a Potentially Responsible Party in connection with the cleanup of a riverbed site adjacent to a commercial property site, acquired by MBI in 1999. The riverbed site is 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 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 or Georgia-Pacific West, Inc., the seller of the commercial property to MBI. Although the LWG originally estimated the overall remedial investigation and feasibility study would cost approximately $10 million, it is now anticipated, on the basis of costs incurred to date and delays attributable to an additional round of sampling and potential further investigative work, that such cost could increase to a total in excess of $60 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 more years to complete. The development of a proposed plan and record of decision on the harbor site is not anticipated to occur until 2010, after which a cleanup plan will be undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, MBI does not believe it is a Responsible Party. In addition, MBI has notified Georgia-Pacific

West, Inc., 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. MBI has entered into an agreement tolling the statute of limitation in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study.

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, 2006, were $18.1 million in 2007, $14.3 million in 2008, $12.0 million in 2009, $10.7 million in 2010, $8.6 million in 2011 and $35.6 million thereafter. Rent expense was $23.7 million, $34.0 million and $30.6 million for the years ended December 31, 2006, 2005 and 2004, respectively.

Purchase commitments

The Company has entered into various commitments, largely an agreement to acquire Cascade as discussed in Note 22 and natural gas and coal supply, purchased power, natural gas transportation and construction materials supply contracts. These commitments range from one to 20 years. The commitments under these contracts as of December 31, 2006, were $693.4 million in 2007, $99.7 million in 2008, $81.8 million in 2009, $62.3 million in 2010, $55.9 million in 2011 and $225.5 million thereafter. Amounts purchased under various commitments for the years ended December 31, 2006, 2005 and 2004, were approximately $281.6 million, $443.9 million and $318.3 million, respectively. These commitments are not reflected in the Company's consolidated financial statements.

Guarantees

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses which Petrobras may incur from certain contingent liabilities specified in the purchase agreement. Centennial has agreed to unconditionally guarantee payment of the indemnity obligations to Petrobras for periods ranging from approximately two to five and a half years from the date of sale. The guarantee was required by Petrobras as a condition to closing the sale of MPX.

In addition, WBI Holdings has guaranteed certain of Fidelity's natural gas and oil price swap and collar agreement obligations. Fidelity did not have obligations under these guarantees at December 31, 2006. 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, 2006, expire in 2007; 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. 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, construction contracts, a conditional purchase agreement and certain other guarantees. At December 31, 2006, the fixed maximum amounts guaranteed under these agreements aggregated $192.9 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $104.3 million in 2007; $15.0 million in 2008; $3.0 million in 2009; $30.3 million in 2010; $23.0 million in 2011; $12.0 million in 2012; $500,000 in 2016; $300,000 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. A guarantee for an unfixed amount estimated at $250,000 at December 31, 2006, has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $700,000 and was reflected on the Consolidated Balance

Sheet at December 31, 2006. 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.

Centennial has outstanding letters of credit to third parties related to insurance policies and other agreements that guarantee the performance of other subsidiaries of the Company. At December 31, 2006, the fixed maximum amounts guaranteed under these letters of credit, which expire in 2007, aggregated $41.9 million. There were no amounts outstanding under the above letters of credit at December 31, 2006.

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. At December 31, 2006, 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 2008 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, 2006, 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 and lease obligations 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 or lease obligations, 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, 2006.

In the normal course of business, Centennial has purchased surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds 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. As of December 31, 2006, approximately $458 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

NOTE 21 - RELATED PARTY TRANSACTIONS

In 2004, Bitter Creek entered into two natural gas gathering agreements with Nance Petroleum. Robert L. Nance, an executive officer and shareholder of St. Mary, also was a member of the Board of Directors of the Company until his retirement on August 17, 2006. The natural gas gathering agreements with Nance Petroleum were effective upon completion of certain high and low pressure gathering facilities, which occurred in 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 $43,000 and $2.5 million in 2006 and 2005, respectively, and are estimated for the next three years to be $3.9 million in 2007, $2.2 million in 2008 and $500,000 in 2009. 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 $1.6 million, $1.2 million and $37,000 in 2006, 2005 and 2004, respectively, and estimated revenues from these contracts for the next three years are $2.1 million in 2007, $3.2 million in 2008 and $4.3 million in 2009. The amount due from Nance Petroleum at December 31, 2006, was $140,000.

In 2005, Montana-Dakota entered into agreements to purchase natural gas from Nance Petroleum through March 31, 2006. Montana-Dakota's expenses under these agreements were $1.9 million in 2006 and $4.2 million in 2005. There were no amounts due to Nance Petroleum at December 31, 2006.

In 2005, Fidelity entered into an agreement for the purchase of an ownership interest in a natural gas and oil property with a third party whereunder it became a party to a joint operating agreement in which St. Mary is the operator of the property. St. Mary receives an overhead fee as operator of this property. The Company recorded its proportionate share of capital costs allocable to its ownership interest in the related property, which were not material to Fidelity.

NOTE 22 - PENDING ACQUISITION

On July 8, 2006, the Company entered into a definitive merger agreement to acquire Cascade, subject to approval of Cascade's shareholders and various regulatory authorities, as well as antitrust clearance under the Hart-Scott-Rodino Act, and the satisfaction of other customary closing conditions. On October 27, 2006, shareholders of Cascade approved the merger agreement. On November 27, 2006, the Company obtained clearance under the Hart-Scott-Rodino Act. Regulatory approvals are anticipated in the third quarter of 2007. The total value of the transaction, including the assumption of certain indebtedness, is approximately $475 million. Cascade's natural gas service areas are concentrated in western and south central Washington and south central and eastern Oregon.

SUPPLEMENTARY FINANCIAL INFORMATION

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2006 and 2005:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2006				
Operating revenues	$ 814,785	$ 973,151	$ 1,190,636	$ 1,092,112
Operating expenses	723,240	848,410	1,006,074	960,724
Operating income	91,545	124,741	184,562	131,388
Income from continuing operations	53,570	71,715	110,098	82,534
Income (loss) from discontinued operations, net of tax	(324)	(273)	(1,611)	48
Net income	53,246	71,442	108,487	82,582
Earnings per common share - basic:				
Earnings before discontinued operations	.30	.40	.61	.46
Discontinued operations, net of tax	---	---	(.01)	---
Earnings per common share - basic	.30	.40	.60	.46
Earnings per common share - diluted:				
Earnings before discontinued operations	.29	.39	.61	.45
Discontinued operations, net of tax	---	---	(.01)	---
Earnings per common share - diluted	.29	.39	.60	.45
Weighted average common shares outstanding:				
Basic	179,823	179,911	180,291	180,900
Diluted	180,915	181,107	181,307	182,094
2005				
Operating revenues	$ 603,667	$ 769,257	$ 1,066,177	$ 1,013,330
Operating expenses	538,164	655,519	916,274	893,317
Operating income	65,503	113,738	149,903	120,013
Income from continuing operations	34,746	80,378	87,523	73,211
Income (loss) from discontinued operations, net of tax	(326)	(205)	(300)	56
Net income	34,420	80,173	87,223	73,267

Earnings per common share - basic:				
Earnings before discontinued operations	.19	.45	.49	.41
Discontinued operations, net of tax	---	---	---	---
Earnings per common share - basic	.19	.45	.49	.41
Earnings per common share - diluted:				
Earnings before discontinued operations	.19	.45	.48	.40
Discontinued operations, net of tax	---	---	---	---
Earnings per common share - diluted	.19	.45	.48	.40
Weighted average common shares outstanding:				
Basic	176,740	177,522	179,429	179,723
Diluted	178,159	178,556	180,584	180,962

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 in the Rocky Mountain and Mid-Continent regions 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, Texas and Wyoming. These rights are in the Bonny Field located in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area located in north-central Montana, the Powder River Basin of Montana and Wyoming, the Tabasco and Texan Gardens fields in Texas, and the Big Horn Basin in 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:

		2006		2005		2004
				(In thousands)		
Subject to amortization	**$**	**1,442,533**	$	1,198,669	$	904,620
Not subject to amortization		**163,975**		82,291		68,984
Total capitalized costs		**1,606,508**		1,280,960		973,604
Less accumulated depreciation, depletion and amortization		**558,980**		456,554		373,932
Net capitalized costs	**$**	**1,047,528**	$	824,406	$	599,672

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

Years ended December 31,	**2006**	*	2005	*	2004	*
			(In thousands)			
Acquisitions:						

Proved properties	$	**75,520**	$ 149,253	$ 188
Unproved properties		**27,383**	16,920	11,031
Exploration		**24,970**	24,385	21,781
Development**		**196,423**	125,633	77,940
Total capital expenditures	$	**324,296**	$ 316,191	$ 110,940

* *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 10, of $8.7 million, $2.5 million and $100,000 for the years ended December 31, 2006, 2005 and 2004, respectively.*

** *Includes expenditures for proved undeveloped reserves of $44.7 million, $37.0 million and $30.3 million for the years ended December 31, 2006, 2005 and 2004, 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,	**2006**	2005	2004
		(In thousands)	
Revenues:			
Sales to affiliates	**$ 232,799**	$ 275,828	$ 190,354
Sales to external customers	**244,499**	159,390	149,660
Production costs	**106,387**	88,068	67,125
Depreciation, depletion and amortization*	**104,741**	84,099	69,946
Pretax income	**266,170**	263,051	202,943
Income tax expense	**100,584**	99,071	73,137
Results of operations for producing activities	**$ 165,586**	$ 163,980	$ 129,806

* *Includes accretion of discount for asset retirement obligations of $2.3 million, $1.5 million and $1.4 million for the years ended December 31, 2006, 2005 and 2004, respectively, in accordance with SFAS No. 143, as discussed in Note 10.*

The following table summarizes the Company's estimated quantities of proved natural gas and oil reserves at December 31, 2006, 2005 and 2004, 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.

	2006		2005		2004	
	Natural Gas	Oil	Natural Gas	Oil	Natural Gas	Oil
			(MMcf/MBbls)			
Proved developed and undeveloped reserves:						
Balance at beginning of year	**489,100**	**21,200**	453,200	17,100	411,700	18,900
Production	**(62,100)**	**(2,100)**	(59,400)	(1,700)	(59,700)	(1,800)
Extensions and discoveries	**123,600**	**2,800**	74,400	500	100,700	500
Improved recovery	**---**	**---**	---	2,600	---	---
	21,700	**4,800**	57,400	3,700	100	---

Purchases of proved reserves						
Sales of reserves in place	**---**	**---**	(1,300)	(100)	---	---
Revisions of previous estimates	**(34,200)**	**400**	(35,200)	(900)	400	(500)
Balance at end of year	**538,100**	**27,100**	489,100	21,200	453,200	17,100

Proved developed reserves:		
January 1, 2004	342,800	15,000
December 31, 2004	376,400	16,400
December 31, 2005	416,700	20,400
December 31, 2006	**412,900**	**22,400**

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:

	2006	2005	2004
		(In thousands)	
Future cash inflows	**$ 3,831,000**	$ 4,778,700	$ 2,848,800
Future production costs	**1,084,000**	1,095,400	803,600
Future development costs	**240,600**	106,400	62,800
Future net cash flows before income taxes	**2,506,400**	3,576,900	1,982,400
Future income tax expense	**759,300**	1,205,700	645,300
Future net cash flows	**1,747,100**	2,371,200	1,337,100
10% annual discount for estimated timing of cash flows	**743,600**	950,400	515,600
Discounted future net cash flows relating to proved natural gas and oil reserves	**$ 1,003,500**	$ 1,420,800	$ 821,500

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

	2006	2005	2004
		(In thousands)	
Beginning of year	**$ 1,420,800**	$ 821,500	$ 736,800
Net revenues from production	(348,400)	(402,900)	(291,600)
Change in net realization	(860,700)	777,700	32,800
Extensions and discoveries, net of future production-related costs	**293,300**	294,800	240,200
Improved recovery, net of future production-related costs	**---**	91,600	---
Purchases of proved reserves, net of future production-related costs	**99,800**	258,300	300
Sales of reserves in place	**---**	(12,500)	---
Changes in estimated future development costs	(25,600)	(13,400)	(5,300)
Development costs incurred during the current year	**60,900**	40,900	39,800
Accretion of discount	**193,800**	106,900	97,100
Net change in income taxes	**295,700**	(339,700)	(36,400)
Revisions of previous estimates	(123,200)	(200,500)	9,600

Other		(2,900)		(1,900)		(1,800)
Net change		(417,300)		599,300		84,700
End of year	**$**	**1,003,500**	$	1,420,800	$	821,500

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, 2006, are $109.3 million in 2007, $54.0 million in 2008 and $9.8 million in 2009. 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 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 - 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 - Report of Independent Registered Public Accounting Firm.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is included under the captions "Item 1. Election of Directors," "Continuing Incumbent Directors," "Information Concerning Executive Officers," "Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement, which is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is included under the caption "Executive Compensation" of the Proxy Statement, which is incorporated herein by reference with the exception of the compensation committee report.

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

EQUITY COMPENSATION PLAN INFORMATION

The following table includes information as of December 31, 2006, with respect to the Company's equity compensation plans:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights	(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))
Equity compensation plans approved by stockholders (1)	2,214,874 (2)	$15.20	8,063,328 (3)(4)
Equity compensation plans not approved by stockholders (5)	785,208	12.83	2,309,328 (6)
Total	3,000,082	$14.58	10,372,656

(1) Consists of the 1992 Key Employee Stock Option Plan, the 1997 Non-Employee Director Long-Term Incentive Plan, the Long-Term Performance-Based Incentive Plan (formerly known as the 1997 Executive Long-Term Incentive Plan) and the Non-Employee Director Stock Compensation Plan.
(2) Includes 688,536 performance shares.
(3) In addition to being available for future issuance upon exercise of options, 357,757 shares under the 1997 Non-Employee Director Long-Term Incentive Plan may instead be issued in connection with stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards, and 6,519,135 shares

under the Long-Term Performance-Based Incentive Plan may instead be issued in connection with stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards.
(4) This amount also includes 508,180 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, nonemployee Directors are awarded 4,050 (adjusted for the three-for-two stock split in July 2006) shares following the Company's annual meeting of stockholders. Additionally, a nonemployee Director may acquire additional shares under the plan in lieu of receiving the cash portion of the Director's retainer or fees.
(5) Consists of the 1998 Option Award Program and the Group Genius Innovation Plan.
(6) In addition to being available for future issuance upon exercise of options, 220,650 shares under the Group Genius Innovation Plan may instead be issued in connection with stock appreciation rights, restricted stock, restricted stock units, performance units, performance stock or other equity-based awards.

The following equity compensation plans have not been approved by the Company's stockholders.

The 1998 Option Award Program
The 1998 Option Award Program is a broad-based plan adopted by the Board of Directors, effective February 12, 1998. The plan permits the grant of nonqualified stock options to employees of the Company and its subsidiaries. The maximum number of shares that may be issued under the plan is 3,795,330. Shares granted may be authorized but unissued shares, treasury shares, or shares purchased on the open market. Option exercise prices are equal to the market value of the Company's shares on the date of the option grant. Optionees receive dividend equivalents on their options, with any credited dividends paid in cash to the optionee if the option vests, or forfeited if the option is forfeited. Vested options remain exercisable for one year following termination of employment due to death or disability and for three months following termination of employment for any other reason.

Unvested options are forfeited upon termination of employment. Subject to the terms and conditions of the plan, the plan's administrative committee determines the number of shares subject to options granted to each participant and the other terms and conditions pertaining to such options, including vesting provisions. All options become immediately exercisable in the event of a change in control of the Company.

In 1998, 337 options (adjusted for the three-for-two stock splits in July 1998, October 2003 and July 2006) were granted to each of approximately 2,200 employees. No officers received grants. These options vested on March 2, 2001. In 2001, 450 options (adjusted for the three-for-two stock splits in October 2003 and July 2006) were granted to each of approximately 5,900 employees. No officers received grants. These options vested on February 13, 2004. As of December 31, 2006, options covering 785,208 shares of common stock were outstanding under the plan and 2,088,678 shares remained available for future grant. Options covering 921,444 shares had been exercised.

The Group Genius Innovation Plan
The Group Genius Innovation Plan was adopted by the Board of Directors, effective May 17, 2001, to encourage employees to share ideas for new business directions for the Company and to reward them when the idea becomes profitable. Employees of the Company and its subsidiaries who are selected by the plan's administrative committee are eligible to participate in the plan. Officers and Directors are not eligible to participate. The plan permits the granting of nonqualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance units, performance stock and other awards. The maximum number of shares that may be issued under the plan is 223,150. Shares granted under the plan may be authorized but unissued shares, treasury shares or shares purchased on the open market. Restricted stockholders have voting rights and, unless determined otherwise by the plan's administrative committee, receive dividends paid on the restricted stock. Dividend equivalents payable in cash may be granted with respect to options and performance shares. The plan's administrative committee determines the number of shares or units subject to awards, and the other terms and conditions of the awards, including vesting provisions and the effect of employment termination. Upon a change in control of the Company, all options and stock appreciation rights become immediately vested and exercisable, all restricted stock becomes immediately vested, all restricted stock units

become immediately vested and are paid out in cash, and target payout opportunities under all performance units, performance stock, and other awards are deemed to be fully earned, with awards denominated in stock paid out in shares and awards denominated in units paid out in cash. As of December 31, 2006, 2,500 shares of stock had been granted to 41 employees.

The remaining information required by this item is included under the caption "Security Ownership" of the Proxy Statement, which is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

There were no transactions with related persons, promoters or certain control persons, as defined in Item 402 of Regulation S-K. The information required by this item with respect to director independence is included under the caption "Corporate Governance" of the Proxy Statement, which is incorporated herein by reference.

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.

PART IV

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.

Consolidated Statements of Income for each of the three years in the period ended December 31, 2006

Consolidated Balance Sheets at December 31, 2006 and 2005

Consolidated Statements of Common Stockholders’ Equity for each of the three years in the period ended December 31, 2006

Consolidated Statements of Cash Flows for each of the three years in the period ended December 31, 2006

Notes to Consolidated Financial Statements

2. Financial Statement Schedules

MDU Resources Group, Inc.
Schedule II - Consolidated Valuation and Qualifying Accounts
Years Ended December 31, 2006, 2005 and 2004

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:					
2006	**$8,031**	**$5,470**	**$1,576**	**$7,352**	**$7,725**
2005	6,801	4,870	1,675	5,315	8,031
2004	8,146	2,663	703	4,711	6,801

** 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

2 Agreement and Plan of Merger by and among MDU Resources Group, Inc., Firemoon Acquisition, Inc. and Cascade Natural Gas Corporation dated as of July 8, 2006, filed by Cascade Natural Gas Corporation as Exhibit 2.1 to Form 8-K dated July 10, 2006, in File No. 1-7196* (1)

3(a) Restated Certificate of Incorporation of the Company, as amended, filed as Exhibit 3(a) to Amendment No. 1 to Registration Statement on Form S-3 on June 13, 2003, in Registration No. 333-104150*

3(b) Company Bylaws, as amended, filed as Exhibit 3.1 to Form 8-K dated November 16, 2006, filed on November 22, 2006, 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, filed on November 14, 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) to Form S-3, in Registration No. 33-66682; and Exhibits 4(e), 4(f) and 4(g) to Form S-8, in Registration No. 33-53896; and Exhibit 4(c)(i) to Form S-3, 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(c) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(f)Centennial Energy Holdings, Inc. Master Shelf Agreement, dated April 29, 2005, among Centennial Energy Holdings, Inc. and the Prudential Insurance Company of America, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(g)Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., The Prudential Insurance Company of America, and certain investors described in the Letter Amendment filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(h)MDU Resources Group, Inc. Credit Agreement, dated June 21, 2005, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as Administrative Agent, and The Other Financial Institutions Party thereto, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

4(i)First Amendment, dated June 30, 2006, to Credit Agreement, dated June 21, 2005, among MDU Resources Group, Inc., Wells Fargo Bank, National Association, as administrative agent, and certain lenders described in the credit agreement, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*

4(j)Centennial Energy Holdings, Inc. Credit Agreement, dated August 26, 2005, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4(a) to Form 10-Q for the quarter ended September 30, 2005, filed on November 3, 2005, in File No. 1-3480*

+10(a)1992 Key Employee Stock Option Plan, as revised**

+10(b)Supplemental Income Security Plan, as amended and restated, effective November 16, 2006**

+10(c)Directors' Compensation Policy, as amended**

+10(d)Deferred Compensation Plan for Directors, as amended, filed as Exhibit 10(e) to Form 10-K for the year ended December 31, 2002, filed on February 28, 2003, in File No. 1-3480*

+10(e)Non-Employee Director Stock Compensation Plan, as revised**

+10(f)1997 Non-Employee Director Long-Term Incentive Plan, as revised**

+10(g)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, filed on November 14, 2002, in File No. 1-3480*

+10(h)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, filed on August 6, 2004, in File No. 1-3480*

+10(i)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, filed on November 14, 2002, in File No. 1-3480*

+10(j)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, filed on August 6, 2004, in File No. 1-3480*

+10(k)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, filed on November 14, 2002, in File No. 1-3480*

+10(l)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, filed on August 6, 2004, in File No. 1-3480*

+10(m)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, filed on August 6, 2004, in File No. 1-3480*

+10(n)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, filed on November 14, 2002, in File No. 1-3480*

+10(o)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, filed on August 6, 2004, in File No. 1-3480*

+10(p)Change of Control Employment Agreement between the Company and John G. Harp**

+10(q)1998 Option Award Program, as revised**

+10(r)Group Genius Innovation Plan, as revised**

10(s)Purchase and Sale Agreement between Fidelity and Smith Production Inc., dated April 19, 2005 (Flores), filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

10(t)Purchase and Sale Agreement between Fidelity and Smith Production Inc., dated April 19, 2005 (Tabasco and Texan Gardens), filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

10(u) First Amendment to the Purchase and Sale Agreements between Fidelity and Smith Production Inc., dated April 19, 2005, filed as Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

10(v) Second Amendment to the Purchase and Sale Agreement between Fidelity and Smith Production Inc., dated April 19, 2005, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*

+10(w) WBI Holdings, Inc. Executive Incentive Compensation Plan, as amended, filed as Exhibit 10(e) to Form 10-Q dated March 31, 2006, filed on May 5, 2006, in File No. 1-3480*

+10(x) Knife River Corporation Executive Incentive Compensation Plan, filed as Exhibit 10.5 to Form 8-K dated February 17, 2005, in File No. 1-3480*

+10(y) Long-Term Performance-Based Incentive Plan, as revised**

+10(z) MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended November 17, 2005, filed as Exhibit 10(af) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(aa) Montana-Dakota Utilities Co. Executive Incentive Compensation Plan, as amended November 17, 2005, filed as Exhibit 10(ag) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(ab) Agreement on Retirement, dated November 23, 2005, between the Company and Warren L. Robinson, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(ac) Change of Control Employment Agreement between the Company and Steven L. Bietz, filed as Exhibit 10(ai) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(ad) Change of Control Employment Agreement between the Company and Nicole A. Kivisto, filed as Exhibit 10(aj) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(ae) Change of Control Employment Agreement between the Company and Doran N. Schwartz, filed as Exhibit 10(ak) to Form 10-K for the year ended December 31, 2005, filed on February 22, 2006, in File No. 1-3480*

+10(af) Employment agreement between the Company and John K. Castleberry, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2006, filed on May 5, 2006, in File No. 1-3480*

+10(ag) Supplemental Executive Retirement Plan for John G. Harp, dated December 4, 2006**

+10(ah) Employment Letter for John G. Harp, dated July 20, 2005**

+10(ai) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan**

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**

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* 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.

(1) Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. MDU Resources Group, Inc. hereby undertakes to furnish supplementally copies of any of the omitted schedules upon request by the SEC.

MDU Resources Group, Inc. agrees to furnish to the SEC upon request any instrument with respect to long-term debt that MDU Resources Group, Inc. has not filed as an exhibit pursuant to the exemption provided by Item 601(b)(4)(iii)(A) of Regulation S-K.

SIGNATURES

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

MDU RESOURCES GROUP, INC.

Date: February 21, 2007 **By: /s/ Terry D. Hildestad**
Terry D. Hildestad
(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/ Terry D. Hildestad Terry D. Hildestad (President and Chief Executive Officer)	Chief Executive Officer and Director	February 21, 2007
/s/ Vernon A. Raile Vernon A. Raile (Executive Vice President, Treasurer and Chief Financial Officer)	Chief Financial Officer	February 21, 2007
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Accounting Officer)	Chief Accounting Officer	February 21, 2007
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 21, 2007
/s/ Thomas Everist Thomas Everist	Director	February 21, 2007
/s/ Karen B. Fagg Karen B. Fagg	Director	February 21, 2007
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 21, 2007
/s/ Richard H. Lewis Richard H. Lewis	Director	February 21, 2007
/s/ Patricia L. Moss Patricia L. Moss	Director	February 21, 2007
/s/ John L. Olson John L. Olson	Director	February 21, 2007
 Sister Thomas Welder	Director	February 21, 2007
/s/ John K. Wilson John K. Wilson	Director	February 21, 2007