MDU RESOURCES GROUP INC
Form 10-K
February 23, 2011

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, 2010

OR

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

For the transition period from _____________ to ______________

Commission file number 1-3480

MDU Resources Group, Inc.
(Exact name of registrant as specified in its charter)

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

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	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 whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). 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, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act (Check one):

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o

(Do not check if a smaller reporting company)

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No x.

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2010: $3,392,049,006.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 15, 2011: 188,756,502 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2011 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	
AFUDC	Allowance for funds used during construction
Alusa	Tecnica de Engenharia Electrica - Alusa
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
BART	Best available retrofit technology
Bbl	Barrel
Bcf	Billion cubic feet
Bcfe	Billion cubic feet equivalent
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Big Stone Station II	Formerly proposed coal-fired electric generating facility near Big Stone City, South Dakota (the Company had anticipated ownership of at least 116 MW)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
Brazilian Transmission Lines	Company's equity method investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE and a portion of the ownership interests in ECTE were sold in the fourth quarter of 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CBNG	Coalbed natural gas
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
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 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 State District Court	Colorado Thirteenth Judicial District Court, Yuma County
Company	MDU Resources Group, Inc.
dk	Decatherm

Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act

ECTE	Empresa Catarinense de Transmissão de Energia S.A. (10.01 percent ownership interest at December 31, 2010, 14.99 percent ownership interest sold in the fourth quarter of 2010)
ENTE	Empresa Norte de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
ERTE	Empresa Regional de Transmissão de Energia S.A. (entire 13.3 percent ownership interest sold in the fourth quarter of 2010)
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
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital (acquired October 1, 2008)
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
LWG	Lower Willamette Group
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels
MBI	Morse Bros., Inc., an indirect wholly owned subsidiary of Knife River (changed its name to Knife River Corporation – Northwest, effective January 1, 2010)
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 Resources

MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
Midwest ISO	Midwest Independent Transmission System Operator, Inc.
Mine Safety Act	Federal Mine Safety and Health Act of 1977, as amended by the Mine Improvement and New Emergency Response Act of 2006
MMBtu	Million Btu
MMcf	Million cubic feet
MMcfe	Million cubic feet equivalent – natural gas equivalents are determined using the ratio of six Mcf of natural gas to one Bbl of oil
MMdk	Million decatherms
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
Oil	Includes crude oil, condensate and natural gas liquids
OPUC	Oregon Public Utilities Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PRC	Planning resource credit – a MW of demand equivalent assigned to generators by the Midwest ISO for meeting system reliability requirements
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
Proxy Statement	Company's 2011 Proxy Statement
PRP	Potentially Responsible Party
PSD	Prevention of Significant Deterioration
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
Ryder Scott	Ryder Scott Company, L.P.
SDPUC	South Dakota Public Utilities Commission
SEC	U.S. Securities and Exchange Commission
SEC Defined Prices	The average price of natural gas and oil during the applicable 12-month period, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions
Securities Act	Securities Act of 1933, as amended

Securities Act Industry Guide 7	Description of Property by Issuers Engaged or to be Engaged in Significant Mining Operations
Sheridan System	A separate electric system owned by Montana-Dakota

SMCRA	Surface Mining Control and Reclamation Act
SourceGas	SourceGas Distribution LLC
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
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
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
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. Cascade distributes natural gas in Oregon and Washington. Intermountain distributes natural gas in Idaho. 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 contracting segment), MDU Construction Services (construction services segment), Centennial Resources and Centennial Capital (both reflected in the Other category).

The Company's equity method investment in the Brazilian Transmission Lines is reflected in the Other category. For additional information, see Item 8 – Note 4.

As of December 31, 2010, the Company had 7,895 employees with 159 employed at MDU Resources Group, Inc., 908 at Montana-Dakota, 31 at Great Plains, 259 at Cascade, 215 at Intermountain, 618 at WBI Holdings, 2,617 at Knife River and 3,088 at MDU Construction Services. 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.

The following information regarding the number of employees represented by labor contracts is as of December 31, 2010.

At Montana-Dakota and Williston Basin, 354 and 83 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through May 30, 2011, and March 31, 2011, for Montana-Dakota and Williston Basin, respectively.

At Cascade, 168 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2012.

At Intermountain, 110 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2013.

Knife River has 43 labor contracts that represent approximately 400 of its construction materials employees. Knife River is in negotiations on nine of its labor contracts.

MDU Construction Services has 113 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 items discussed in Environmental matters in Item 8 – Note 19. There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site and one of the manufactured gas plant sites in Washington.

The Company produces GHG emissions primarily from its fossil fuel electric generating facilities, as well as from natural gas pipeline and storage systems, operations of equipment and fleet vehicles, and oil and natural gas exploration and development activities. GHG emissions also result from customer use of natural gas for heating and other uses. As interest in reductions in GHG emissions has grown, the Company has developed renewable generation with lower or no GHG emissions. Governmental legislative and regulatory initiatives regarding environmental and energy policy are continuously evolving and could negatively impact the Company's operations and financial results. Until legislation and regulation are finalized, the impact of these measures cannot be accurately predicted. The Company will continue to monitor legislative and regulatory activity related to environmental and energy policy initiatives. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description later. In addition, for a discussion of the Company's risks related to environmental laws and regulations, see Item 1A – Risk Factors.

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 more than 124,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2010. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 11 electric generating facilities, as further described under System Supply, System Demand and Competition, and approximately 3,000 and 4,600 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. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises. At December 31, 2010, Montana-Dakota's net electric plant investment was $580.3 million.

The percentage of Montana-Dakota's 2010 retail electric utility operating revenues by jurisdiction is as follows: North Dakota – 61 percent; Montana – 22 percent; Wyoming – 11 percent; and South Dakota – 6 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 and ancillary services 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 day-ahead and real-time energy markets and ancillary services markets. 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, System Demand and Competition 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 maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 525,643 kW in July 2007. 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 2016 will approximate 3 percent annually. The interconnected system consists of 10 electric generating facilities, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 493,055 kW and total net PRCs of 444.3. PRCs are a MW of demand equivalent measure and are allocated to individual generators to meet supply obligations within the Midwest ISO. For 2010, Montana-Dakota's total PRCs, including its firm purchase power contracts, were 553.3. Montana-Dakota's peak demand supply obligation, including firm purchase power contracts, within the Midwest ISO was 529.5 PRCs for 2010. 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, two wind electric generating facilities and a heat recovery electric generating facility supply the balance of Montana-Dakota's interconnected system electric generating capability.

Montana-Dakota has a contract for seasonal capacity from a neighboring utility for 105 MW in 2011, with an option for capacity in 2012. In September 2010, Montana-Dakota entered a contract for capacity of 35 MW for 2011. Montana-Dakota also has a contract for capacity of 110 MW, 115 MW and 120 MW annually for the three-year period from June 1 to May 31, 2013, 2014 and 2015, respectively. Energy also will be purchased as needed from the Midwest ISO market. In 2010, Montana-Dakota purchased approximately 17 percent of its net kWh needs for its interconnected system through the Midwest ISO market.

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date attributable to Montana-Dakota sales to retail customers on that system was approximately 60,600 kW in July 2007. Montana-Dakota has a power supply contract with Black Hills Power to purchase up to 49,000 kW of capacity annually through December 31, 2016. Wygen III, which commenced commercial operation in the second quarter of 2010, serves a portion of the needs of its Sheridan-area customers.

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

Generating Station	Type	Nameplate Rating (kW)	Summer Capability (kW) (a)	PRC (a)	2010 Net Generation (kWh in thousands)
Interconnected System:					
North Dakota:					
Coyote (b)	Steam	103,647	107,500	96.3	752,049
Heskett	Steam	86,000	101,300	94.1	468,761
Williston	Combustion Turbine	7,800	9,600	8.0	(5)(c)
Glen Ullin	Heat Recovery	7,500	5,300	4.9	37,246
Cedar Hills	Wind	19,500	(d)	(d)	30,488
South Dakota:					
Big Stone (b)	Steam	94,111	108,000	96.9	642,542
Montana:					
Lewis & Clark	Steam	44,000	52,300	52.0	315,372
Glendive	Combustion Turbine	77,347	77,020	69.8	6,979
Miles City	Combustion Turbine	23,150	21,600	20.7	1,022
Diamond Willow	Wind	30,000	1,560	1.6 (e)	67,899
		493,055	484,180	444.3	2,322,353
Sheridan System:					
Wyoming:					
Wygen III (b)	Steam	28,000	N/A	N/A	149,935
		521,055	484,180	444.3	2,472,288

(a) Interconnected system only. The summer capability values were used previously by MAPP for determining available generation for resource adequacy. The Midwest ISO requires generators to obtain their summer capability, or PRCs, by applying the generators forced outage factor against the results of a generator output verification test. Wind generator's PRCs are calculated based on a wind capacity study performed annually by the Midwest ISO. PRCs are used to meet supply obligations with the Midwest ISO.
(b) Reflects Montana-Dakota's ownership interest.
(c) Station use, to meet Midwest ISO's requirements, exceeded generation.
(d) Pending accreditation.
(e) A portion is pending accreditation.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland under contracts that expire in May 2016, April 2011 and December 2012, respectively. Montana-Dakota is in negotiations on a new coal contract for the Heskett Station. 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 Lewis & Clark and existing Heskett coal supply agreements provide for the purchase of coal necessary to supply the coal requirements of these stations at contracted pricing. Montana-Dakota estimates the Heskett and Lewis & Clark coal requirement to be in the range of 500,000 to 600,000 tons and 250,000 to 350,000 tons per contract year, respectively.

Montana-Dakota has a coal supply agreement, which meets the majority of the Big Stone Station's fuel requirements, for the purchase of 1.5 million tons of coal in 2011 and 2012 with Peabody Coalsales, LLC at contracted pricing.

Montana-Dakota has a coal supply agreement with Wyodak Resources Development Corp., which provides for the purchase of coal necessary to supply the coal requirements of Wygen III at contracted pricing through June 1, 2060. Montana-Dakota estimates the maximum annual coal consumption of the facility to be 585,000 tons per year.

The average cost of coal purchased, including freight, at Montana-Dakota's electric generating stations (including the Big Stone, Coyote and Wygen III stations) was as follows:

Years ended December 31,	2010	2009	2008
Average cost of coal per MMBtu	$1.55	$1.52	$1.49
Average cost of coal per ton	$22.60	$22.05	$21.45

Montana-Dakota expects that it has secured adequate capacity available through existing baseload generating stations, renewable generation, turbine peaking stations, demand reduction programs and firm contracts to meet the peak customer demand requirements of its customers through mid-2015. 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 purchase contracts or the Midwest ISO capacity auction. For additional information regarding potential power generation projects, see Item 7 – MD&A – Prospective Information – Electric and natural gas distribution.

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.

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.

Regulatory Matters and Revenues Subject to Refund Fuel adjustment clauses contained in North Dakota and South Dakota jurisdictional electric rate schedules allow Montana-Dakota to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In North Dakota, Montana-Dakota is deferring electric fuel and purchased power costs (excluding demand charges) that are greater or less than amounts presently being recovered through its existing rate schedules. In Montana, a monthly Fuel and Purchased Power Tracking Adjustment mechanism allows Montana-Dakota to reflect 90 percent of the increases or decreases in fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring 90 percent of costs that are greater or less than amounts presently being recovered through its existing rate schedules. In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota to reflect increases or decreases in fuel and purchased power costs (including demand charges) related to power supply and Montana-Dakota is deferring 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 14 to 25 months from the time such costs are paid. For additional information, see Item 8 – Note 6.

Montana-Dakota filed an application with the NDPSC and the MTPSC for electric rate increases on April 19, 2010, and August 12, 2010, respectively. For additional information, see Item 8 – Note 18.

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 they operate. 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. The Heskett Station Title V Operating Permit was renewed in 2010. Title V Operating Permit renewal applications for the Glendive and Miles City combustion turbine facilities were submitted to the Montana Department of Environmental Quality in February 2010 and April 2010, respectively.

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.

Montana-Dakota incurred $1.0 million of environmental capital expenditures in 2010. Capital expenditures are estimated to be $2.4 million, $16.8 million and $31.1 million in 2011, 2012 and 2013, respectively, to maintain environmental compliance as new emission controls are required, including the installation of a BART air quality control system at the Big Stone Station. Additional expenditures for this BART project are expected during 2014 to 2016 of approximately $78 million. Projects for 2011 through 2013 will also include sulfur-dioxide, nitrogen oxide and mercury control equipment installation at electric generating stations. Montana-Dakota's capital and operational expenditures could also be affected in a variety of ways by potential new GHG legislation or regulation. In particular, such legislation or regulation would likely increase capital expenditures for renewable energy resources and operational costs associated with GHG emissions compliance until carbon capture technology becomes economical, at which time capital expenditures may be necessary to incorporate such technology into existing or new generating facilities. Montana-Dakota expects that it will recover the operational and capital expenditures for GHG regulatory compliance in its rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Great Plains, Cascade and Intermountain, which sell natural gas at retail, serving over 839,000 residential, commercial and industrial customers in 335 communities and adjacent rural areas across eight states as of December 31, 2010, and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 18,000 miles. The natural gas distribution operations 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. These operations intend to protect their service areas and seek renewal of all expiring franchises. At December 31, 2010, the natural gas distribution operations' net natural gas distribution plant investment was $950.6 million.

The percentage of the natural gas distribution operations' 2010 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho – 31 percent; Washington – 28 percent; North Dakota – 12 percent; Oregon – 9 percent; Montana – 8 percent; South Dakota – 6 percent; Minnesota – 4 percent; and Wyoming – 2 percent. The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Dickinson, Wahpeton, Williston, Minot and Jamestown; central and eastern Oregon, including Bend and Pendleton; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton, Longview, Moses Lake, Mount Vernon, Tri-Cities, Walla Walla and Yakima; 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.

Competition in varying degrees exists between natural gas and other fuels and forms of energy. The natural gas distribution operations 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 interruptible customers can avail themselves of the advantages of open access transportation on various regional transmission pipelines, including the systems of Williston Basin and Northwest Pipeline GP. These services have enhanced the natural gas distribution operations' competitive posture with alternative fuels, although certain customers have bypassed the distribution systems by directly accessing transmission pipelines within close proximity. These bypasses did not have a material effect on results of operations.

The natural gas distribution operations 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 with several major transporters, including Williston Basin and Northwest Pipeline GP. The natural gas distribution operations have contracts for storage services to provide gas supply during the winter heating season and to meet peak day demand with various storage providers, including Williston Basin, Questar Pipeline Company and Northwest Pipeline GP. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements as well as changes in market price. The natural gas distribution operations believe that, based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next decade.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs within a period ranging from 12 to 28 months.

Montana-Dakota's North Dakota and South Dakota natural gas tariffs contain weather normalization mechanisms applicable to firm customers that adjust the distribution delivery charge revenues to reflect weather fluctuations during the November 1 through May 1 billing periods.

Cascade has received approval for decoupling its margins from weather and conservation in Oregon. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC. Cascade also had received approval for a decoupling mechanism in Washington that allowed for the recovery of margin differences resulting from customer conservation. This mechanism expired in the fourth quarter of 2010 and is not currently expected to be renewed.

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

Natural gas distribution operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Certain of the natural gas distribution operations routinely handle PCBs from their natural gas operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required. Capital and operational expenditures for natural gas distribution operations could be affected in a variety of ways by potential new GHG legislation or regulation. In particular, such legislation or regulation would likely increase capital expenditures for energy efficiency and conservation programs and operational costs associated with GHG emissions compliance. Natural gas distribution operations expect to recover the operational and capital expenditures for GHG regulatory compliance in rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

In 2010, the natural gas distribution operations reserved $6.4 million for remediation of a former manufactured gas plant in Washington. The natural gas distribution operations did not incur any other material environmental expenditures in 2010. Except as to what may be ultimately determined with regard to the issues described later, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2013.

Montana-Dakota has had an economic interest in five 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. Cascade has had an economic interest in nine former manufactured gas plants within its service territory. Cascade has been involved in the investigation and remediation of a manufactured gas plant in Washington, as previously discussed. In addition, Cascade has been involved with other PRPs in the investigation of a manufactured gas plant site in Oregon, with remediation of this site pending additional investigation and received a third party claim notice in 2008 for one additional site in Washington. See Item 8 – Note 19 for a further discussion of these three manufactured gas plants. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Construction Services
General MDU Construction Services specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes specialty equipment. These services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

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

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, 2010, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops. At December 31, 2010, MDU Construction Services' net plant investment was $50.4 million.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2010, was approximately $373 million compared to $383 million at December 31, 2009. MDU Construction Services expects to complete a significant amount of this backlog during the year ending December 31, 2011. 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. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

MDU Construction Services works with the National Electrical Contractors Association, the IBEW and other trade associations on hiring and recruiting a qualified workforce.

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 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 markets 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 2010 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2013.

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 33 compressor stations in 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, 2010, Williston Basin's net plant investment was $286.1 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 of WBI Holdings, 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 Texas. In total, these facilities include over 1,900 miles of field gathering lines and 86 owned or leased compression stations, some of which interconnect with Williston Basin's system. Bitter Creek also provides a variety of energy-related services such as cathodic protection, water hauling, contract compression operations, measurement services and 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 majority of its pipeline and energy services business in the northern Great Plains and Rocky Mountain regions of the United States.

For information regarding natural gas gathering operations litigation, see Item 8 – Note 19.

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 firm 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, 2010, represented 51 percent of Williston Basin's subscribed firm transportation contract demand. Montana-Dakota has firm transportation agreements with Williston Basin, the majority of which expire 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 expiring in July 2015.

Bitter Creek competes with several pipelines for existing customers and for the expansion 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 and the variety of services it offers, 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. Williston Basin's storage facilities enable its customers to purchase natural gas at more uniform daily volumes throughout the year and meet winter peak requirements.

Natural gas supplies emanate from traditional and nontraditional production activities in the region and from off-system supply sources. While certain traditional regional supply sources are in various stages of decline, incremental supply from nontraditional sources have been developed which has helped support Williston Basin's supply needs. This includes new natural gas supply associated with the continued development of the Bakken area in Montana and North Dakota. The Powder River Basin, including the Company's CBNG assets, also provides a nontraditional natural gas supply to the Williston Basin system. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. 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.

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, the Clean Water Act, the NEPA and other state and federal regulations. Administration of many provisions of these laws has been delegated to the states where Williston Basin and Bitter Creek operate. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

Detailed environmental assessments and/or environmental impact statements are included in the FERC's permitting processes for both the construction and abandonment of Williston Basin's natural gas transmission pipelines, compressor stations and storage facilities.

WBI Holdings' pipeline and energy services operations did not incur any material environmental expenditures in 2010 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2013.

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 continues to seek additional reserve and production growth opportunities through these activities. Future growth is dependent upon its success in these endeavors. Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests.

Fidelity's business is focused primarily in two core regions: Rocky Mountain and Mid-Continent/Gulf States.

Rocky Mountain

Fidelity's properties in this region are primarily in Colorado, Montana, North Dakota, Utah and Wyoming. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Bonny Field in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area in north-central Montana, the Powder River Basin of Montana and Wyoming, the Bakken area in North Dakota, the Paradox Basin of Utah, and the Big Horn Basin of Wyoming. In 2010, Fidelity acquired natural gas properties in the Green River Basin in Wyoming and became the operator on a portion of these properties. Fidelity also owns nonoperated natural gas and oil interests and undeveloped acreage positions in this region. During 2010, Fidelity acquired undeveloped acreage in the emerging Niobrara play in Wyoming and expanded its acreage position in the North Dakota Bakken play.

Mid-Continent/Gulf States

This region includes properties in Alabama, Louisiana, New Mexico, Texas and the Offshore Gulf of Mexico. The Offshore Gulf of Mexico interests are primarily located in the shallow waters off

the coasts of Texas and Louisiana. 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 and Rusk County in eastern Texas. In addition, Fidelity owns several nonoperated interests and undeveloped acreage positions in this region.

Operating Information Annual net production by region for 2010 was as follows:

Region	Natural Gas (MMcf)*	Oil (MBbls)	Total (MMcfe)	Percent of Total	
Rocky Mountain	39,160	2,365	53,350	76	%
Mid-Continent/Gulf States	11,231	897	16,613	24	
Total	50,391	3,262	69,963	100	%

* Baker field and Bowdoin field represent 28 percent and 20 percent, respectively, of total annual net natural gas production, and are the only fields that contain 15 percent or more of the Company's total proved reserves.

Annual net production by region for 2009 was as follows:

Region	Natural Gas (MMcf)*	Oil (MBbls)	Total (MMcfe)	Percent of Total	
Rocky Mountain	41,635	2,182	54,729	73	%
Mid-Continent/Gulf States	14,997	929	20,570	27	
Total	56,632	3,111	75,299	100	%

* Baker field and Bowdoin field represent 28 percent and 19 percent, respectively, of total annual net natural gas production, and are the only fields that contain 15 percent or more of the Company's total proved reserves.

Annual net production by region for 2008 was as follows:

Region	Natural Gas (MMcf)*	Oil (MBbls)	Total (MMcfe)	Percent of Total	
Rocky Mountain	47,504	1,698	57,691	70	%
Mid-Continent/Gulf States	17,953	1,110	24,612	30	
Total	65,457	2,808	82,303	100	%

* Baker field and Bowdoin field represent 28 percent and 18 percent, respectively, of total annual net natural gas production, and are the only fields that contain 15 percent or more of the Company's total proved reserves.

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, 2010, were as follows:

	Gross*	Net**
Productive wells:		
Natural gas	3,756	3,054
Oil	3,754	284
Total	7,510	3,338
Developed acreage (000's)	716	405
Undeveloped acreage (000's)	974	544

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

Exploratory and Development Wells The following table reflects activities related to Fidelity's natural gas and oil wells drilled and/or tested during 2010, 2009 and 2008:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2010	3	4	7	133	1	134	141
2009	1	2	3	104	–	104	107
2008	11	4	15	251	9	260	275

At December 31, 2010, there were 50 gross (25 net) wells in the process of drilling or under evaluation, 43 of which were development wells and seven of which were exploratory wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing of the majority of these wells within the next 12 months.

The information in the preceding table 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, services 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 and operational laws and regulations. Fidelity believes it is in substantial compliance with these regulations.

The ongoing operations of Fidelity are subject to the Clean Air Act, the Clean Water Act, the NEPA, ESA and other state, federal and local regulations. Administration of many provisions of these laws has been delegated to the states where Fidelity operates. Permit terms vary and all permits carry operational compliance conditions. Some permits require annual renewal, some have terms ranging from one to five years and others have no expiration date. Permits are renewed and modified, as necessary, based on defined permit expiration dates, operational demand and/or regulatory changes.

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

In connection with production operations, Fidelity has incurred certain capital expenditures related to water handling. For 2010, capital expenditures for water handling in compliance with current laws and regulations were approximately $2.5 million and are estimated to be approximately $450,000, $4.2 million and $3.1 million in 2011, 2012 and 2013, respectively.

Proved Reserve Information Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. Other factors used in the reserve estimates are prices, estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

The reserve estimates are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. The technical person responsible for overseeing the preparation of the reserve estimates holds a bachelor of science degree in geological engineering and a master of science degree in geology, has over 25 years experience in petroleum engineering and reserve estimation, and is a member of multiple professional organizations. In addition, the Company engages an independent third party to audit its proved reserves. Ryder Scott reviewed the Company's proved reserve quantity estimates as of December 31, 2010. The technical person at Ryder Scott primarily responsible for overseeing the reserves audit is a Senior Vice President with over 30 years of experience in estimating and auditing reserves attributable to oil and gas properties, holds a bachelor of science degree in mechanical engineering, is a registered professional engineer, and is a member of multiple professional organizations.

Fidelity's recoverable proved reserves by region at December 31, 2010, are as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total	PV-10 Value* (in millions)
Rocky Mountain	334,671	24,358	480,821	74 %	$846.5
Mid-Continent/Gulf States	113,726	8,509	164,775	26	283.4
Total reserves	448,397	32,867	645,596	100 %	1,129.9
Discounted future income taxes					233.8
Standardized measure of discounted future net cash flows relating to proved reserves					$896.1

* Pre-tax PV-10 value is a non-GAAP financial measure that is derived from the most directly comparable GAAP financial measure which is the standardized measure of discounted future net cash flows. The standardized measure of discounted future net cash flows disclosed in Item 8 – Supplementary Financial Information, is presented after deducting discounted future income taxes, whereas the PV-10 value is presented before income taxes. Pre-tax PV-10 value is commonly used by the Company to evaluate properties that are acquired and sold and to assess the potential return on investment in the Company's natural gas and oil properties. The Company believes pre-tax PV-10 value is a useful supplemental disclosure to the standardized measure as the Company believes readers may utilize this value as a basis for comparison of the relative size and value of the Company's reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. However, pre-tax PV-10 value is not a substitute for the standardized measure of discounted future net cash flows. Neither the Company's pre-tax PV-10 value nor the standardized measure of discounted future net cash flows purports to represent the fair value of the Company's natural gas and oil properties.

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

Construction Materials and Contracting

General Knife River operates construction materials and contracting 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 mix and supply 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 contracting services.

For information regarding construction materials litigation, see Item 8 – Note 19.

The construction materials business had approximately $420 million in backlog at December 31, 2010, compared to $459 million at December 31, 2009. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2011.

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 products and services, the loss of which would have a material 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 such as 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 internal 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 previously 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 applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

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

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 1.0 billion tons of the 1.1 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. 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 the three-year average sales from 2008 through 2010. 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, 2010, and sales for the years ended December 31, 2010, 2009 and 2008:

Production Area	Number of Sites (Crushed Stone) owned	Number of Sites (Crushed Stone) leased	Number of Sites (Sand & Gravel) owned	Number of Sites (Sand & Gravel) leased	Tons Sold (000's) 2010	2009	2008	Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Anchorage, AK	-	-	1	-	854	891	1,267	16,700	N/A	17
Hawaii	-	6	-	-	1,412	1,940	2,467	62,210	2011-2064	32
Northern CA	-	-	9	1	1,043	1,215	2,054	48,350	2014	34
Southern CA	-	2	-	-	619	337	106	94,269	2035	Over 100
Portland, OR	1	3	6	3	2,521	2,718	4,074	245,721	2012-2055	79
Eugene, OR	3	4	4	1	1,311	1,097	1,633	170,947	2011-2046	Over 100
Central OR/WA/Idaho	1	2	4	4	1,192	1,436	1,686	106,640	2011-2077	74
Southwest OR	5	4	11	6	1,505	1,871	2,248	101,169	2011-2048	54
Central MT	-	-	2	2	971	1,220	2,086	30,064	2013-2027	21
Northwest MT	-	-	7	2	1,362	1,289	1,198	46,848	2011-2020	37
Wyoming	-	-	1	2	447	655	720	13,594	2013-2019	22
Central MN	-	1	37	30	1,527	1,868	1,367	80,001	2011-2028	50
Northern MN	2	-	16	6	401	838	333	27,939	2012-2016	53
ND/SD	-	-	2	23	1,106	699	876	37,156	2011-2031	42
Iowa	-	1	1	13	642	545	1,405	9,079	2011-2017	11
Texas	1	2	-	2	1,648	1,080	1,619	16,709	2011-2025	12
Sales from other sources					4,788	4,296	5,968			
					23,349	23,995	31,107	1,107,396		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2010, are comprised of 467 million tons that are owned and 640 million tons that are leased. Approximately 58 percent of the tons under lease have lease expiration dates of 20 years or more. The weighted average years remaining on all leases containing estimated probable aggregate reserves is approximately 27 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2008 through 2010 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 62 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

The following table summarizes Knife River's aggregate reserves at December 31, 2010, 2009 and 2008, and reconciles the changes between these dates:

	2010	2009	2008
		(000's of tons)	
Aggregate reserves:			

Beginning of year	1,125,491	1,145,161	1,215,253
Acquisitions	3,600	21,400	27,650
Sales volumes*	(18,561)	(19,699)	(25,139)
Other**	(3,134)	(21,371)	(72,603)
End of year	1,107,396	1,125,491	1,145,161

*Excludes sales from other sources.

** Includes property sales and revisions of previous estimates.

Environmental Matters Knife River's construction materials and contracting 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. Individual permits applicable to Knife River's various operations are managed largely by local operations, particularly as they relate to application, modification, renewal, compliance and reporting procedures.

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. 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, certain in-water mining operations are subject to provisions of the Clean Water Act that are administered by the Army Corps. Knife River operates several such operations, including gravel bar skimming and dredging operations, and Knife River has the associated permits as required. The expiration dates of these permits vary, with five years generally being the longest term.

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 2010 and, except as to what may be ultimately determined with regard to the issue described later, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2013.

In December 2000, MBI was named by the EPA as a PRP 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 19.

Mine Safety The Dodd-Frank Act requires disclosure of certain mine safety information which has been included in Item 9B – Other Information.

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, which are subject to various external influences that cannot be controlled.

These factors include: fluctuations in natural gas and 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 identify, 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. Volatility in natural gas and oil prices could negatively affect the results of operations and cash flows of the Company's natural gas and oil production and pipeline and energy services businesses.

The regulatory approval, permitting, 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 and cash flows.

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, its results of operations and cash flows.

Economic volatility affects the Company's operations, as well as the demand for its products and services and the value of its investments and investment returns including its pension and other postretirement benefit plans and, may have a negative impact on the Company's future revenues and cash flows.

The global demand for natural resources, interest rates, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. The current economic slowdown has negatively affected the level of public and private expenditures on projects and the timing of these projects which, in turn, has negatively affected the demand for the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services will likely continue to be adversely impacted by the downturn in the industries the Company serves, as well as in the economy in general. State and federal budget issues may continue to negatively affect the funding available for infrastructure spending. This continued economic volatility could have a material adverse effect on the Company's results of operations, cash flows and asset values.

Changing market conditions could negatively affect the market value of assets held in the Company's pension and other postretirement benefit plans and may increase the amount and accelerate the timing of required funding contributions.

The Company relies on financing sources and capital markets. Access to these markets may be adversely affected by factors beyond the Company's control. 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. As a result, the market value of the Company's common stock may be adversely affected. If the Company issues a substantial amount of common stock it could have a dilutive effect on its existing shareholders.

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 further 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
- Deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks

Economic turmoil, market disruptions and volatility in the securities trading markets, as well as other factors including changes in the Company's financial condition, results of operations and prospects, may adversely affect the market price of the Company's common stock.

The Company currently has authorization to issue and sell up to $1.0 billion of securities pursuant to a registration statement on file with the SEC. The issuance of a substantial amount of the Company's common stock, whether sold pursuant to the registration statement, issued in connection with an acquisition or otherwise issued, or the perception that such an issuance could occur, may adversely affect the market price of the Company's common stock.

The Company is exposed to credit risk and the risk of loss resulting from the nonpayment and/or nonperformance by the Company's customers and counterparties.

If any of the Company's customers or counterparties were to experience financial difficulties or file for bankruptcy, the Company could experience difficulty in collecting receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties could have a negative impact on the Company's results of operations and cash flows.

The backlogs at the Company's construction services and construction materials and contracting businesses are subject to delay or cancellation and may not be realized.

Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation and the contracts in the Company's backlog are subject to changes in the scope of services to be provided as well as adjustments to the costs relating to the applicable contracts. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and economic factors beyond the Company's control, including the current economic slowdown. Accordingly, there is no assurance that backlog will be realized.

Actual quantities of recoverable natural gas and oil reserves and discounted future net cash flows from those reserves may vary significantly from estimated amounts.

The process of estimating natural gas and oil reserves is complex. Reserve estimates are based on assumptions relating to natural gas and oil pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations, and the percentage of interest owned by the Company in the properties. The reserve estimates are prepared for each of the Company's properties by internal engineers assigned to an asset team by geographic area. The internal engineers analyze available geological, geophysical, engineering and economic data for each geographic area. The internal engineers make various assumptions regarding this data. The extent, quality and reliability of this data can vary. Although the Company has prepared its reserve estimates in accordance with guidelines established by the industry and the SEC, significant changes to the reserve estimates may occur based on actual results of production, drilling, costs and pricing.

The Company bases the estimated discounted future net cash flows from proved reserves on prices and current costs in accordance with SEC requirements. Actual future prices and costs may be significantly different. Sustained downward movements in natural gas and oil prices could result in future noncash write-downs of the Company's natural gas and oil properties.

Environmental and Regulatory Risks
The Company's operations are subject to 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 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, delays as a result of litigation and administrative proceedings, and compliance, remediation, containment, monitoring and reporting obligations, particularly with regard to laws relating to power plant operations and natural gas and oil 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 laws and regulations may be revised and new laws and regulations seeking to protect the environment may be adopted or become applicable to the Company. These laws and regulations could require the Company to limit the use or output of certain facilities, restrict the use of certain fuels, install pollution control equipment or initiate pollution control technologies, remediate environmental contamination, remove or reduce environmental hazards, or prevent or limit the development of resources. Revised or additional laws and regulations, that result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

The EPA has issued draft regulations that outline several possible approaches for coal combustion residuals management under the RCRA. One approach, designating coal ash as a hazardous waste would significantly change and increase the costs of managing coal ash at five plants that supply electricity to customers of Montana-Dakota. This designation also could significantly increase costs for Knife River, which beneficially uses fly ash as a cement replacement in ready-mixed concrete and road base applications.

Hydraulic fracturing involves injecting water, sand and chemicals under pressure into rock formations to stimulate natural gas and oil production. Legislative initiatives and regulatory studies, proceedings or initiatives at federal or state agencies focused on the hydraulic fracturing process could result in additional compliance, reporting and disclosure requirements. If legislation or regulations are enacted, the Company could experience increased compliance costs and operating restrictions or delays in its ability to develop its natural gas and oil reserves.

Global climate change initiatives to reduce GHG emissions could adversely impact the Company's electric generation operations.

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. The EPA finalized its endangerment finding for GHG emissions in late 2009, and its GHG "Tailoring" Rule in 2010. Starting in 2011, the GHG "Tailoring" Rule will require new large emission sources, such as coal-fired electric generating facilities, and existing large emission sources that make modifications that increase GHG emission to obtain permits and conduct best available control technology evaluations to limit the amount of GHG emission from these sources.

The primary GHG emitted from the Company's operations is carbon dioxide from combustion of fossil fuels at Montana-Dakota's electric generating facilities, particularly its coal-fired electric generating facilities. Approximately 70 percent of Montana-Dakota's owned generating capacity and more than 90 percent of the electricity it generates is from coal-fired plants. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants.

While the future of GHG regulation is uncertain, Montana-Dakota's electric generating facilities may be subject to climate change laws or regulations within the next few years. Implementation of treaties, legislation or regulations to reduce GHG emissions could affect Montana-Dakota's electric utility operations by requiring expanded energy conservation efforts or increased development of renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs. Montana-Dakota's ability to recover costs incurred to comply with new regulations and programs also will be important in determining the financial impact on the Company.

Due to the uncertain availability of technologies to control GHG emissions and the unknown obligations that potential GHG emission legislation or regulations may create, the Company cannot determine the financial impact on its operations. If Montana-Dakota does not receive timely and full recovery of GHG emission compliance costs from its customers, then such costs could have an adverse impact on the results of its operations.

The Company's CBNG operations could be adversely impacted by the outcome of lawsuits challenging its CBNG development.

One of the Company's subsidiaries is and has been subject to litigations and administrative proceedings in connection with its CBNG development. These proceedings have caused delays in CBNG drilling activity and resulted in more restrictive discharge limitations. There is the possibility that the Company will be the subject of similar future proceedings. 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.

The Company is subject to government regulations that may delay and/or have a negative impact on its business and its results of operations and cash flows. Statutory and regulatory requirements also may limit another party's ability to acquire the Company.

The Company is subject to regulation or governmental actions by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return, financing, industry rate structures, health care legislation, tax legislation 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 and cash flows. Approval from a number of federal and state regulatory agencies would need to be obtained by any potential acquirer of the Company. The approval process could be lengthy and the outcome uncertain.

Other Risks

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

The Company's results of operations can be affected by changes in the weather. Weather conditions influence the demand for electricity and natural gas, affect the price of energy commodities, affect the ability to perform services at the construction services and construction materials and contracting 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. Climate changes could change the intensity and frequency of severe weather conditions. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial condition and cash flows.

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, volatility in 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 increase in competition could negatively affect the Company's results of operations, financial condition and cash flows.

The Company could be subject to limitations on its ability to pay dividends.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on its common stock. Regulatory, contractual and legal limitations, as well as capital requirements and the Company's financial performance or cash flows, could limit the earnings of the Company's divisions and subsidiaries which, in turn, could restrict the Company's ability to pay dividends on its common stock and adversely affect the Company's stock price.

An increase in costs related to obligations under multi-employer pension plans could have a material negative effect on the Company's results of operations and cash flows.

Various operating subsidiaries of the Company participate in approximately 60 multi-employer pension plans for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

The Company may be obligated to increase its contributions to underfunded plans that are classified as being in endangered, seriously endangered, or critical status as defined by the Pension Protection Act of 2006. Plans classified as being in one of these statuses are required to adopt rehabilitation plans or funding improvement plans to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes approximately 35 of the multi-employer plans to which it contributes are currently in endangered, seriously endangered, or critical status.

The Company may also be required to increase its contributions to multi-employer plans where the other participating employers in such plans withdraw from the plan and are not able to contribute an amount sufficient to fund the unfunded liabilities associated with their participants in the plans. The amount and timing of any increase in the Company's required contributions to multi-employer pension plans may also depend upon one or more of the following factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, the industry for which contributions are made, future determinations that additional plans reach endangered, seriously endangered or critical status, government regulations and the actual return on assets held in the plans, among others. The Company may experience increased operating expenses as a result of the required contributions to multi-employer pension plans, which may have a material adverse effect on the Company's financial condition, results of operations or cash flows.

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded.

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 ability to obtain adequate and timely cost recovery for the Company's regulated operations through regulatory proceedings
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services
- The 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 and funding requirements

Item 1B. Unresolved Staff 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 19.

Part II

Item 5. Market for the Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases 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 2010 and 2009 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Per Share
2010			
First quarter	$24.15	$19.54	$.1575
Second quarter	22.90	17.11	.1575
Third quarter	20.48	17.61	.1575
Fourth quarter	21.27	19.52	.1625
			$.6350
2009			
First quarter	$22.89	$12.79	$.1550
Second quarter	19.76	15.70	.1550
Third quarter	21.16	17.44	.1550
Fourth quarter	24.22	19.96	.1575
			$.6225

As of December 31, 2010, the Company's common stock was held by approximately 15,100 stockholders of record.

The following table includes information with respect to the Company's purchase of equity securities:

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2010	—			
November 1 through November 30, 2010	—			
December 1 through December 31, 2010	6,678	$20.51		
Total	6,678			

(1) Represents shares of common stock purchased on the open market for the Company's non-employee directors who elected to receive additional shares of common stock in lieu of a portion of their cash retainer.

(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

Item 6. Selected Financial Data

	2010	2009 *	2008 **	2007	2006	2005
Selected Financial Data						
Operating revenues (000's):						
Electric	$211,544	$196,171	$208,326	$193,367	$187,301	$181,238
Natural gas distribution	892,708	1,072,776	1,036,109	532,997	351,988	384,199
Construction services	789,100	819,064	1,257,319	1,103,215	987,582	687,125
Pipeline and energy services	329,809	307,827	532,153	447,063	443,720	477,311
Natural gas and oil production	434,354	439,655	712,279	514,854	483,952	439,367
Construction materials and contracting	1,445,148	1,515,122	1,640,683	1,761,473	1,877,021	1,604,610
Other	7,727	9,487	10,501	10,061	8,117	6,038
Intersegment eliminations	(200,695)	(183,601)	(394,092)	(315,134)	(335,142)	(375,965)
	$3,909,695	$4,176,501	$5,003,278	$4,247,896	$4,004,539	$3,403,923
Operating income (loss) (000's):						
Electric	$48,296	$36,709	$35,415	$31,652	$27,716	$29,038
Natural gas distribution	75,697	76,899	76,887	32,903	8,744	7,404
Construction services	33,352	44,255	81,485	75,511	50,651	28,171
Pipeline and energy services	46,310	69,388	49,560	58,026	57,133	43,507
Natural gas and oil production	143,169	(473,399)	202,954	227,728	231,802	230,383
Construction materials and contracting	63,045	93,270	62,849	138,635	156,104	105,318
Other	858	(219)	2,887	(7,335)	(9,075)	(5,298)
	$410,727	$(153,097)	$512,037	$557,120	$523,075	$438,523
Earnings (loss) on common stock (000's):						
Electric	$28,908	$24,099	$18,755	$17,700	$14,401	$13,940
Natural gas distribution	36,944	30,796	34,774	14,044	5,680	3,515
Construction services	17,982	25,589	49,782	43,843	27,851	14,558
Pipeline and energy services	23,208	37,845	26,367	31,408	32,126	22,867
Natural gas and oil production	85,638	(296,730)	122,326	142,485	145,657	141,625
Construction materials and contracting	29,609	47,085	30,172	77,001	85,702	55,040
Other	21,046	7,357	10,812	(4,380)	(4,324)	13,061
Earnings (loss) on common stock before income (loss) from discontinued operations	243,335	(123,959)	292,988	322,101	307,093	264,606
	(3,361)	—	—	109,334	7,979	9,792

Income (loss) from discontinued operations, net of tax						
	$239,974	$(123,959)	$292,988	$431,435	$315,072	$274,398
Earnings (loss) per common share before discontinued operations – diluted	$1.29	$(.67)	$1.59	$1.76	$1.69	$1.47
Discontinued operations, net of tax	(.02)	—	—	.60	.05	.06
	$1.27	$(.67)	$1.59	$2.36	$1.74	$1.53
Common Stock Statistics						
Weighted average common shares outstanding – diluted (000's)	188,229	185,175	183,807	182,902	181,392	179,490
Dividends per common share	$.6350	$.6225	$.6000	$.5600	$.5234	$.4934
Book value per common share	$14.22	$13.61	$14.95	$13.80	$11.88	$10.43
Market price per common share (year end)	$20.27	$23.60	$21.58	$27.61	$25.64	$21.83
Market price ratios:						
Dividend payout	50%	N/A	38%	24%	30%	32%
Yield	3.2%	2.7%	2.9%	2.1%	2.1%	2.3%
Price/earnings ratio	16.0x	N/A	13.6x	11.7x	14.7x	14.3x
Market value as a percent of book value	142.5%	173.4%	144.3%	200.1%	215.8%	209.2%
Profitability Indicators						
Return on average common equity	9.1%	(4.9)%	11.0%	18.5%	15.6%	15.7%
Return on average invested capital	7.0%	(1.7)%	8.0%	13.1%	10.6%	10.8%
Fixed charges coverage, including preferred dividends	4.1x	— ***	5.3x	6.4x	6.4x	6.6x
General						
Total assets (000's)	$6,303,549	$5,990,952	$6,587,845	$5,592,434	$4,903,474	$4,423,562
Total long-term debt (000's)	$1,506,752	$1,499,306	$1,647,302	$1,308,463	$1,254,582	$1,206,510
Capitalization ratios:						
Common equity	64%	63%	61%	66%	63%	61%
Total debt	36	37	39	34	37	39
	100%	100%	100%	100%	100%	100%

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*Reflects a $384.4 million after-tax noncash write-down of natural gas and oil properties.
**Reflects an $84.2 million after-tax noncash write-down of natural gas and oil properties.
***For more information on fixed charges coverage, including preferred dividends, see Item 7 – MD&A.

Notes:

- Common stock share amounts reflect the Company's three-for-two common stock split effected in July 2006.
- Cascade and Intermountain, natural gas distribution businesses, were acquired on July 2, 2007, and October 1, 2008, respectively.

	2010	2009	2008	2007	2006	2005
Electric						
Retail sales (thousand kWh)	2,785,710	2,663,560	2,663,452	2,601,649	2,483,248	2,413,704
Sales for resale (thousand kWh)	58,321	90,789	223,778	165,639	483,944	615,220
Electric system summer generating and firm purchase capability – kW (Interconnected system)	594,180	594,700	597,250	571,160	547,485	546,085
Electric system summer and firm purchase contract PRCs (Interconnected system)	553.3	*	*	*	*	*
Electric system peak demand obligation, including firm purchase contracts, PRCs (Interconnected system)	529.5	*	*	*	*	*
Demand peak – kW (Interconnected system)	525,643	525,643	525,643	525,643	485,456	470,470
Electricity produced (thousand kWh)	2,472,288	2,203,665	2,538,439	2,253,851	2,218,059	2,327,228
Electricity purchased (thousand kWh)	521,156	682,152	516,654	576,613	833,647	892,113
Average cost of fuel and purchased power per kWh	$.021	$.023	$.025	$.025	$.022	$.020
Natural Gas Distribution**						
Sales (Mdk)	95,480	102,670	87,924	52,977	34,553	36,231
Transportation (Mdk)	135,823	132,689	103,504	54,698	14,058	14,565
Degree days (% of normal)						
Montana-Dakota	98 %	104 %	103 %	93 %	87 %	91 %
Cascade	96 %	105 %	108 %	102 %	—	—
Intermountain	100 %	107 %	90 %	—	—	—
Pipeline and Energy Services						
Transportation (Mdk)	140,528	163,283	138,003	140,762	130,889	104,909
Gathering (Mdk)	77,154	92,598	102,064	92,414	87,135	82,111
Customer natural gas storage balance (Mdk)	58,784	61,506	30,598	50,219	51,477	27,999
Natural Gas and Oil Production						
Production:						
Natural gas (MMcf)	50,391	56,632	65,457	62,798	62,062	59,378
Oil (MBbls)	3,262	3,111	2,808	2,365	2,041	1,707
Total production (MMcfe)	69,963	75,299	82,303	76,988	74,307	69,622
Average realized prices (including hedges):						
Natural gas (per Mcf)	$4.36	$5.16	$7.38	$5.96	$6.03	$6.11

Oil (per Bbl)	$65.85	$47.38	$81.68	$59.26	$50.64	$42.59
Average realized prices (excluding hedges):						
Natural gas (per Mcf)	$3.57	$2.99	$7.29	$5.37	$5.62	$6.87
Oil (per Bbl)	$66.71	$49.76	$82.28	$59.53	$51.73	$48.73
Proved reserves:						
Natural gas (MMcf)	448,397	448,425	604,282	523,737	538,100	489,100
Oil (MBbls)	32,867	34,216	34,348	30,612	27,100	21,200
Total reserves (MMcfe)	645,596	653,724	810,371	707,409	700,700	616,400
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	23,349	23,995	31,107	36,912	45,600	47,204
Asphalt (tons)	6,279	6,360	5,846	7,062	8,273	9,142
Ready-mixed concrete (cubic yards)	2,764	3,042	3,729	4,085	4,588	4,448
Aggregate reserves (000's tons)	1,107,396	1,125,491	1,145,161	1,215,253	1,248,099	1,273,696

* Information not available for periods prior to 2010.

** Cascade and Intermountain were acquired on July 2, 2007, and October 1, 2008, respectively.

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 and equity securities. In the event that access to the commercial paper markets were to become unavailable, the Company may need to borrow under its credit agreements. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments.

The key strategies for each of the Company's business segments and certain related business challenges are summarized below. For a summary of the Company's business segments, see Item 8 – Note 15.

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations, including electric generation with a diverse resource mix that includes renewable generation, and transmission build-out, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment.

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 and environmental regulations. The ability of these segments to grow through acquisitions is subject to significant competition. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of electric generating facilities and transmission lines may be subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which may necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas.

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; retaining, developing and recruiting 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, retention of key personnel, managing through downturns in the economy and effective management of working capital are ongoing challenges.

Pipeline and Energy Services
Strategy Utilize 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, transmission and storage facilities; expansion of related energy services; and incremental expansion of pipeline capacity to allow customers access to more liquid and higher-priced markets.

Challenges Challenges for this segment include: energy price volatility; natural gas basis differentials; environmental and regulatory requirements; recruitment and retention of a skilled workforce; and competition from other natural gas pipeline and energy services companies.

Natural Gas and Oil Production
Strategy Apply technology and utilize 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 both in new and existing areas to further expand the segment's asset base. By optimizing existing operations and taking advantage of new and incremental growth opportunities, this segment's goal is to add value by increasing both reserves and production over the long term so as to generate competitive returns on investment.

Challenges Volatility in natural gas and oil prices; timely receipt of necessary permits and approvals; environmental and regulatory requirements; recruitment and retention of a skilled workforce; availability of drilling rigs, materials, auxiliary equipment and industry-related field services, and inflationary pressure on development and operating costs; and competition from other natural gas and oil companies are ongoing challenges for this segment.

Construction Materials and Contracting
Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; and continue growth through organic and acquisition opportunities. 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 (liquid asphalt, diesel fuel, cement and other materials), and negotiation of contract price escalation provisions. 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 permitted aggregate reserves being significant. A key

element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges The economic downturn has adversely impacted operations, particularly in the private market. The current economic challenges have resulted in increased competition in certain construction markets and lowered margins. Delays in the reauthorization of the federal highway bill and volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel, continue to be a concern. This business unit expects to continue cost containment efforts and a greater emphasis on industrial, energy and public works projects.

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 (loss) by each of the Company's businesses.

Years ended December 31,	2010	2009	2008
	(Dollars in millions, where applicable)		
Electric	$28.9	$24.1	$18.7
Natural gas distribution	37.0	30.8	34.8
Construction services	18.0	25.6	49.8
Pipeline and energy services	23.2	37.8	26.4
Natural gas and oil production	85.6	(296.7)	122.3
Construction materials and contracting	29.6	47.1	30.2
Other	21.0	7.3	10.8
Earnings (loss) before discontinued operations	243.3	(124.0)	293.0
Loss from discontinued operations, net of tax	(3.3)	—	—
Earnings (loss) on common stock	$240.0	$(124.0)	$293.0
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	$1.29	$(.67)	$1.60
Discontinued operations, net of tax	(.01)	—	—
Earnings (loss) per common share – basic	$1.28	$(.67)	$1.60
Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	$1.29	$(.67)	$1.59
Discontinued operations, net of tax	(.02)	—	—
Earnings (loss) per common share – diluted	$1.27	$(.67)	$1.59
Return on average common equity	9.1%	(4.9)%	11.0%

2010 compared to 2009 Consolidated earnings for 2010 were $240.0 million compared to a loss of $124.0 million in 2009. This increase was due to:

- Absence of the 2009 noncash write-down of natural gas and oil properties of $384.4 million (after tax), higher average realized oil prices, increased oil production and lower general and administrative expense, partially offset by lower average realized natural gas prices, decreased natural gas production and higher production taxes at the natural gas and oil production business
- A $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines, as discussed in Item 8 – Note 4, as well as a $3.3 million (after tax) loss from discontinued operations, as discussed in Item 8 – Note 3. Both of these items are included in the Other category.

Partially offsetting these increases were:

- Lower liquid asphalt oil, ready-mixed concrete and asphalt margins and volumes, as well as decreased construction margins, partially offset by lower selling, general and administrative expense at the construction materials and contracting segment
- Higher operation and maintenance expense, primarily due to a natural gas gathering arbitration charge of $16.5 million (after tax) and lower gathering volumes, partially offset by higher storage services revenue at the pipeline and energy services business

2009 compared to 2008 Consolidated loss for 2009 was $124.0 million compared to earnings of $293.0 million in 2008. This decrease was due to:

- A noncash write-down of natural gas and oil properties of $384.4 million (after tax) as well as lower average realized natural gas and oil prices of 30 percent and 42 percent, respectively and decreased natural gas production of 13 percent, partially offset by the absence of the 2008 noncash write-down of natural gas and oil properties of $84.2 million (after tax), lower depreciation, depletion and amortization expense and lower production taxes at the natural gas and oil production business
- Lower construction workloads, partially offset by lower general and administrative expense at the construction services business

Partially offsetting these decreases were:

- Increased earnings from liquid asphalt oil and asphalt operations, as well as lower selling, general and administrative expense at the construction materials and contracting business
- Increased volumes transported to storage, higher storage services revenue and lower operation and maintenance expense at the pipeline and energy services business

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

Electric

Years ended December 31,	2010	2009	2008
	(Dollars in millions, where applicable)		
Operating revenues	$211.6	$196.2	$208.3
Operating expenses:			
Fuel and purchased power	63.1	65.7	75.4
Operation and maintenance	63.8	60.7	64.8
Depreciation, depletion and amortization	27.3	24.7	24.0
Taxes, other than income	9.1	8.4	8.7
	163.3	159.5	172.9
Operating income	48.3	36.7	35.4
Earnings	$28.9	$24.1	$18.7
Retail sales (million kWh)	2,785.7	2,663.5	2,663.4
Sales for resale (million kWh)	58.3	90.8	223.8
Average cost of fuel and purchased power per kWh	$.021	$.023	$.025

2010 compared to 2009 Electric earnings increased $4.8 million (20 percent) compared to the prior year due to:

- Higher electric retail sales margins, primarily due to implementation of higher rates in Wyoming, as well as interim rates in North Dakota
- Higher retail sales volumes of 5 percent, primarily to residential and small commercial and industrial customers, reflecting increased customers and demand

Partially offsetting these increases were:

- Higher operation and maintenance expense of $1.8 million (after tax), primarily costs due to storm damage, as well as expenses at Wygen III, which commenced operation in the second quarter of 2010
- Lower other income of $1.6 million (after tax), primarily lower allowance for funds used during construction related to electric generation projects, which were placed in service in 2010
- Increased depreciation, depletion and amortization expense of $1.6 million (after tax), including the effects of higher property, plant and equipment balances
- Higher net interest expense of $1.3 million (after tax), resulting from higher average borrowings and lower capitalized interest

2009 compared to 2008 Electric earnings increased $5.4 million (28 percent) compared to the prior year due to:

- Higher other income, primarily allowance for funds used during construction of $5.0 million (after tax)
- Lower operation and maintenance expense of $2.3 million (after tax), largely payroll and benefit-related costs

Partially offsetting these increases were decreased sales for resale margins due to lower average rates of 31 percent and decreased volumes of 59 percent due to lower market demand and decreased plant generation.

Natural Gas Distribution

Years ended December 31,	2010	2009	2008
	(Dollars in millions, where applicable)		
Operating revenues	$892.7	$1,072.8	$1,036.1
Operating expenses:			
Purchased natural gas sold	589.3	757.6	757.6
Operation and maintenance	137.4	140.5	123.6
Depreciation, depletion and amortization	43.0	42.7	32.6
Taxes, other than income	47.3	55.1	45.4
	817.0	995.9	959.2
Operating income	75.7	76.9	76.9
Earnings	$37.0	$30.8	$34.8
Volumes (MMdk):			
Sales	95.5	102.7	87.9
Transportation	135.8	132.7	103.5
Total throughput	231.3	235.4	191.4
Degree days (% of normal)*			
Montana-Dakota	98 %	104 %	103 %
Cascade	96 %	105 %	108 %
Intermountain	100 %	107 %	90 %
Average cost of natural gas, including transportation, per dk	$6.17	$7.38	$8.14

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

Note: Intermountain was acquired on October 1, 2008. For further information, see Item 8 – Note 2.

2010 compared to 2009 The natural gas distribution business experienced an increase in earnings of $6.2 million (20 percent) compared to the prior year due to:

- An income tax benefit of $4.8 million related to a reduction in deferred income taxes associated with property, plant and equipment
- Lower operation and maintenance expense of $2.7 million (after tax), largely lower bad debt expense and benefit-related costs
- Higher nonregulated energy-related services of $1.4 million (after tax), including pipeline project activity
- Lower net interest expense of $1.3 million (after tax), primarily due to higher capitalized interest and lower average borrowings
- Higher other income of $1.1 million (after tax), primarily allowance for funds used during construction due to higher rates
- Increased demand-related transportation volumes of $900,000 (after tax), primarily industrial customers

Partially offsetting these increases were decreased retail sales volumes, largely resulting from warmer weather than last year.

2009 compared to 2008 The natural gas distribution business experienced a decrease in earnings of $4.0 million (11 percent) compared to the prior year due to:

- Absence of a $4.4 million (after tax) gain on the sale of Cascade's natural gas management service in June 2008
- Lower earnings from energy-related services of $2.0 million (after tax)

Partially offsetting these decreases was lower operation and maintenance expense at existing operations of $2.2 million (after tax), including lower payroll and benefit-related costs.

Construction Services

Years ended December 31,	2010	2009	2008
		(In millions)	
Operating revenues	$789.1	$819.0	$1,257.3
Operating expenses:			
Operation and maintenance	719.7	736.3	1,122.7
Depreciation, depletion and amortization	12.1	12.8	13.4
Taxes, other than income	23.9	25.7	39.7
	755.7	774.8	1,175.8
Operating income	33.4	44.2	81.5
Earnings	$18.0	$25.6	$49.8

2010 compared to 2009 Construction services earnings decreased $7.6 million (30 percent) compared to the prior year, primarily due to lower construction workloads and margins, which reflect the effects of the economic downturn. Lower general and administrative expense of $7.9 million (after tax), largely lower payroll-related costs and lower bad debt expense partially offset the earnings decrease. Lower construction workloads and margins in the Western and Central regions were partially offset by higher construction workloads and margins in the Mountain region.

2009 compared to 2008 Construction services earnings decreased $24.2 million (49 percent) compared to the prior year, primarily due to lower construction workloads, largely in the Western region, partially offset by lower general and administrative expense of $6.7 million (after tax), largely payroll-related.

Pipeline and Energy Services

Years ended December 31,	2010	2009	2008
	(Dollars in millions)		
Operating revenues	$329.8	$307.8	$532.2
Operating expenses:			
Purchased natural gas sold	153.9	138.8	373.9
Operation and maintenance	90.6	63.1	73.8
Depreciation, depletion and amortization	26.0	25.5	23.6
Taxes, other than income	13.0	11.0	11.3
	283.5	238.4	482.6
Operating income	46.3	69.4	49.6
Earnings	$23.2	$37.8	$26.4
Transportation volumes (MMdk)	140.5	163.3	138.0
Gathering volumes (MMdk)	77.2	92.6	102.1
Customer natural gas storage balance (MMdk):			
Beginning of period	61.5	30.6	50.2
Net injection (withdrawal)	(2.7)	30.9	(19.6)
End of period	58.8	61.5	30.6

2010 compared to 2009 Pipeline and energy services earnings decreased $14.6 million (39 percent) largely due to:

- Higher operation and maintenance expense, primarily due to a natural gas gathering arbitration charge of $26.6 million ($16.5 million after tax), as discussed in Item 8 – Note 19, partially offset by lower costs related to natural gas storage litigation, largely due to an insurance recovery. The natural gas storage litigation was settled in July 2009.
- Lower gathering volumes of $4.2 million (after tax), largely resulting from customers experiencing normal production declines
- Decreased transportation volumes of $2.0 million (after tax), largely lower volumes transported to storage resulting from decreased customer demand

Partially offsetting the earnings decrease was higher storage services revenue of $6.0 million (after tax), largely higher storage balances.

2009 compared to 2008 Pipeline and energy services earnings increased $11.4 million (44 percent) largely due to:

- Increased transportation volumes of $4.9 million (after tax), largely volumes transported to storage
- Lower operation and maintenance expense of $4.5 million (after tax), largely associated with the natural gas storage litigation, which was settled in July 2009
- Higher storage services revenues of $3.1 million (after tax)
- Higher gathering rates of $2.2 million (after tax)

Partially offsetting the earnings improvement were decreased gathering volumes of 9 percent. Results also reflect lower operating revenues and lower purchased natural gas sold, both related to lower natural gas prices. The previous table also reflects lower operation and maintenance expense and revenues related to energy-related service projects.

Natural Gas and Oil Production

Years ended December 31,	2010	2009	2008
	(Dollars in millions, where applicable)		
Operating revenues:			
Natural gas	$219.6	$292.3	$482.8
Oil	214.8	147.4	229.3
Other	—	—	.2
	434.4	439.7	712.3
Operating expenses:			
Purchased natural gas sold	—	—	.1
Operation and maintenance:			
Lease operating costs	68.5	70.1	82.0
Gathering and transportation	23.5	24.0	24.8
Other	32.5	39.2	41.0
Depreciation, depletion and amortization	130.5	129.9	170.2
Taxes, other than income:			
Production and property taxes	35.5	29.1	54.7
Other	.7	.8	.8
Write-down of natural gas and oil properties	—	620.0	135.8
	291.2	913.1	509.4
Operating income (loss)	143.2	(473.4)	202.9
Earnings (loss)	$85.6	$(296.7)	$122.3
Production:			
Natural gas (MMcf)	50,391	56,632	65,457
Oil (MBbls)	3,262	3,111	2,808
Total Production (MMcfe)	69,963	75,299	82,303
Average realized prices (including hedges):			
Natural gas (per Mcf)	$4.36	$5.16	$7.38
Oil (per Bbl)	$65.85	$47.38	$81.68
Average realized prices (excluding hedges):			
Natural gas (per Mcf)	$3.57	$2.99	$7.29
Oil (per Bbl)	$66.71	$49.76	$82.28
Average depreciation, depletion and amortization rate, per equivalent Mcf	$1.77	$1.64	$2.00
Production costs, including taxes, per equivalent Mcf:			
Lease operating costs	$.98	$.93	$1.00
Gathering and transportation	.34	.32	.30
Production and property taxes	.51	.39	.66
	$1.83	$1.64	$1.96

2010 compared to 2009 The natural gas and oil production business reported earnings of $85.6 million in 2010 compared to a loss of $296.7 million in 2009 due to:

- Absence of the 2009 noncash write-down of natural gas and oil properties of $384.4 million (after tax), as discussed in Item 8 – Note 1
- Higher average realized oil prices of 39 percent
- Increased oil production of 5 percent, largely related to drilling activity in the Bakken area, partially offset by normal production declines at certain existing properties

- Lower general and administrative expense of $4.2 million (after tax), including the absence of rig contract termination costs in 2009
- Lower net interest expense of $1.3 million (after tax), primarily due to lower average borrowings and higher capitalized interest, partially offset by higher effective interest rates

Partially offsetting these increases were:

- Lower average realized natural gas prices of 16 percent
- Decreased natural gas production of 11 percent, largely related to normal production declines at existing properties, partially offset by production from the Green River Basin properties, which were acquired in April 2010, as discussed in Item 8 – Note 2
- Higher production and property taxes of $4.0 million (after tax), largely resulting from higher natural gas and oil prices excluding hedges

2009 compared to 2008 The natural gas and oil production business experienced a loss of $296.7 million in 2009 compared to earnings of $122.3 million in 2008 due to:

- A noncash write-down of natural gas and oil properties of $384.4 million (after tax) in 2009, partially offset by the absence of the 2008 noncash write-down of natural gas and oil properties of $84.2 million (after tax), both discussed in Item 8 – Note 1
- Lower average realized natural gas and oil prices of 30 percent and 42 percent, respectively
- Decreased natural gas production of 13 percent, largely related to normal production declines at certain properties

Partially offsetting these decreases were:

- Lower depreciation, depletion and amortization expense of $25.0 million (after tax), due to lower depletion rates and decreased combined production. The lower depletion rates are largely the result of the write-downs of natural gas and oil properties in December 2008 and March 2009.
- Lower production taxes of $15.8 million (after tax) associated largely with lower average prices
- Increased oil production of 11 percent, largely related to drilling activity in the Bakken area, partially offset by normal production declines at certain properties
- Decreased lease operating expenses of $7.3 million (after tax)

Construction Materials and Contracting

Years ended December 31,	2010	2009	2008
	(Dollars in millions)		
Operating revenues	$1,445.1	$1,515.1	$1,640.7
Operating expenses:			
Operation and maintenance	1,260.4	1,292.0	1,437.9
Depreciation, depletion and amortization	88.3	93.6	100.9
Taxes, other than income	33.4	36.2	39.1
	1,382.1	1,421.8	1,577.9
Operating income	63.0	93.3	62.8
Earnings	$29.6	$47.1	$30.2
Sales (000's):			
Aggregates (tons)	23,349	23,995	31,107
Asphalt (tons)	6,279	6,360	5,846
Ready-mixed concrete (cubic yards)	2,764	3,042	3,729

2010 compared to 2009 Earnings at the construction materials and contracting business decreased $17.5 million (37 percent) due to:

- Lower earnings of $11.1 million (after tax), as a result of lower liquid asphalt oil margins and volumes, largely due to increased competition
- Lower earnings of $7.3 million (after tax) resulting from lower ready-mixed concrete margins and volumes, primarily due to less available work and increased competition
- Decreased construction margins of $7.1 million (after tax), largely due to increased competition
- Lower earnings of $5.7 million (after tax) resulting from lower asphalt margins and volumes, primarily due to increased competition, as well as higher asphalt oil costs

Partially offsetting the decreases were lower selling, general and administrative expense of $8.2 million (after tax) and higher gains on the sale of property, plant and equipment of $5.5 million (after tax). Increased competition is largely the result of the continuing economic downturn in the residential and commercial markets.

2009 compared to 2008 Earnings at the construction materials and contracting business increased $16.9 million (56 percent) due to:

- Higher earnings of $17.2 million (after tax) resulting from higher liquid asphalt oil and asphalt volumes and margins
- Lower selling, general and administrative expense of $14.6 million (after tax), largely the result of cost reduction measures
- Higher aggregate margins of $8.3 million (after tax)

Partially offsetting the increases were:

- Lower aggregate and ready-mixed concrete sales volumes as a result of the continuing economic downturn
- Lower gains on the sale of property, plant and equipment of $5.5 million (after tax)

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,	2010	2009	2008
		(In millions)	
Other:			
Operating revenues	$7.7	$9.5	$10.5
Operation and maintenance	4.8	8.1	5.9
Depreciation, depletion and amortization	1.6	1.3	1.3
Taxes, other than income	.5	.3	.4
Intersegment transactions:			
Operating revenues	$200.7	$183.6	$394.1
Purchased natural gas sold	175.4	156.7	365.7
Operation and maintenance	25.3	26.9	28.4

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 certain 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 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 growth and earnings projections.

MDU Resources Group, Inc.

- Earnings per common share for 2011, diluted, are projected in the range of $1.05 to $1.30. The Company expects the approximate percentage of 2011 earnings per common share by quarter to be:

  – First quarter – 15 percent

  – Second quarter – 20 percent

  – Third quarter – 35 percent

  – Fourth quarter – 30 percent

- Although near term market conditions are uncertain, 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.

- The Company continually seeks opportunities to expand through strategic acquisitions and organic growth opportunities.

Electric and natural gas distribution

- The Company continues to realize efficiencies and enhanced service levels through its efforts to standardize operations, share services and consolidate back-office functions among its four utility companies.

- In April 2010, the Company filed an application with the NDPSC for an electric rate increase, as discussed in Item 8 – Note 18.

- In August 2010, the Company filed an application with the MTPSC for an electric rate increase, as discussed in Item 8 – Note 18.

- The Company is analyzing potential projects for accommodating load growth and replacing purchased power contracts with company-owned generation. The Company is reviewing the construction of natural gas-fired combustion.

- The Company is pursuing opportunities associated with the potential development of high-voltage transmission lines and system enhancements targeted towards delivery of renewable energy from the wind rich regions that lie within its traditional electric service territory to major metropolitan areas. The Company has signed a contract to develop a 30-mile high-voltage power line in southeast North Dakota to move power to the electric grid from a proposed 150-MW wind farm. The project will total approximately $20 million and will include substation upgrades. Pending regulatory approval, construction is expected to begin in 2011. The Company's customers will not bear any of the costs associated with the project as costs will be recovered through an approved interconnect tariff.

- The South Dakota Board of Minerals and Environment has approved rules implementing the South Dakota Regional Haze Program that upon approval by the EPA will require the Big Stone Station to install and operate a BART air quality control system to reduce emissions of particulate matter, sulfur dioxide and nitrogen oxides as early as January 2016. The Company’s share of the cost of this air quality control system could exceed $100 million. At this time the Company believes continuing to operate Big Stone Station with the upgrade is the best option; however, the Company will continue to review alternatives. The Company intends to seek recovery of costs related to the above matter in electric rates charged to customers.

Construction services

- Work backlog as of December 31, 2010, was approximately $373 million, which is comparable to the December 31, 2009, backlog and $56 million higher than the September 30, 2010, backlog of $317 million. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including refinery work.

- As a result of the continued slow economic recovery, the Company anticipates margins in 2011 to be comparable to 2010 levels.

- The Company is pursuing expansion in high-voltage transmission and substation construction, renewable resource construction, governmental facilities, refinery turnaround projects and utility service work.

- The Company continues to focus on costs and efficiencies to enhance margins. Selling, general and administrative expenses are down 31 percent in 2010 as compared to 2008, the peak earnings year for this segment.

- With its highly skilled technical workforce, this group is prepared to take advantage of government stimulus spending on transmission infrastructure.

Pipeline and energy services

- The Company continues to pursue expansion of facilities and services offered to customers. Energy development within its geographic region, which includes portions of Colorado, Wyoming, Montana and North Dakota, is expanding, most notably the Bakken of North Dakota and eastern Montana. The Company owns an extensive natural gas pipeline system in the Bakken area. Ongoing energy development is expected to have many direct and indirect benefits to this business.

- The Company continues to pursue the expansion of its existing natural gas pipeline in the Bakken production area in northwestern North Dakota. It is currently soliciting customer interest in a 27 MMcf per day expansion of capacity out of the area targeted for late 2011.

- Final agreements have been executed to construct approximately 12 miles of high pressure transmission pipeline providing takeaway capacity for processed natural gas in northwestern North Dakota. The project is expected to be completed in the fourth quarter. The Company believes it is in a good position to provide similar services for other natural gas processing facilities in the area.

- The Company has three natural gas storage fields including the largest storage field in North America located near Baker, Montana. The Company continues to see strong interest in its storage services and is pursuing a project to increase its firm deliverability from the Baker Storage field by 125 MMcf per day. The Company has received commitment on approximately 30 percent of the total potential project and is moving forward on this phase with a projected in-service date of November 2011, subject to regulatory approval.

Natural gas and oil production

- The Company expects to spend approximately $306 million in capital expenditures in 2011. The Company continues its focus on returns by allocating a growing portion of its capital investment into the production of oil in the current commodity price environment. The Company’s capital program reflects further exploitation of existing properties, acquisition of additional leasehold acreage, and exploratory drilling. The 2011 planned capital expenditure total does not include potential acquisitions of producing properties.

- For 2011, the Company expects a 5 percent to 10 percent increase in oil production offset by a 4 percent to 8 percent decrease in natural gas production. If natural gas prices recover, the Company believes it is positioned to spend additional capital on drilling its low cost natural gas properties.

- Bakken – Mountrail County, North Dakota

  - The Company owns approximately 16,000 net acres of leaseholds targeting the middle Bakken and Three Forks formations with average production of approximately 3,700 net Bbls per day. The drilling of 13 operated and participation in various non-operated wells is planned for 2011 with approximately $52 million of capital expenditures. The Company plans to drill 12 wells annually for the two-year period 2012 through 2013.

  - Over 50 future well sites have been identified, 20 middle Bakken infill locations and the remainder Three Forks locations. Estimated gross ultimate recovery per well for the middle Bakken wells is 250,000 Bbls to 400,000 Bbls.

- Bakken – Stark County, North Dakota

  - The Company holds approximately 50,000 net exploratory leasehold acres, targeting the Three Forks formation. The first test well was recently completed, the Kostelecky 31-6H, with an initial 24-hour production rate of 1,257 Bbls of oil and 519 Mcf of gas, or 1,343 Bbls of oil equivalents. Its second test well, the Oukrop 34-34H, was also recently completed. While it has not been production tested, initial flow back of fluids is less than expected. A third test well, Wock 14-11H, is drilled and waiting on completion. The Company anticipates drilling 6 additional operated wells on this acreage and participating in various non-operated wells in Stark County in 2011 with capital of approximately $37 million.

  - Based on well results, the Company plans to drill 12 or more wells annually beginning in 2012.

  - Based on 640-acre spacing, the acreage holds over 75 potential drill sites. Estimated gross ultimate recovery rates per well are 250,000 to 500,000 Bbls of oil equivalents. Based on initial well results and results by other producers, the play appears promising.

- Bakken

  - In the second quarter of 2011, the Company plans to add an additional drilling rig in the Bakken.

- Niobrara – southeastern Wyoming

  - The Company holds approximately 65,000 net exploratory leasehold acres in this emerging oil play. The Company is completing seismic evaluation work on this acreage and expects to begin drilling two exploratory wells in 2011.

  - If successful, the Company plans to initiate a drilling program of approximately 12 wells annually starting in 2012.

  - The Company also expects to participate in various non-operated wells in the Niobrara.

- The Company has more than 100 future locations on this acreage based on 640-acre spacing. Although this is an emerging exploratory play, early results by certain other producers appear promising.

- Texas

  - Based on low natural gas prices, the Company is targeting areas that have the potential for higher liquids content. The Company has approximately $48 million of capital targeted in 2011.

- Other opportunities

  - The Company holds approximately 80,000 net exploratory leasehold acres in the Heath Shale oil prospect in Montana. Plans include drilling a test well in 2011.

  - The Company continues to pursue acquisitions of additional leaseholds. Approximately $50 million of capital has been allocated to leasehold acquisitions in 2011, focusing on expansion of existing positions and new opportunities.

- Reserve information

  - For additional information on the Company's reserves, see Item 8 – Supplementary Financial Information. The December 31, 2010, proved reserve figure does not yet include reserves for the Company’s acreage in the Bakken – Stark County or Niobrara areas because of the exploratory nature of these plays.

- Earnings guidance reflects estimated natural gas and oil prices for February through December as follows:

Index*	Price Per Mcf/Bbl
Natural gas:	
NYMEX	$4.25 to $4.75
Ventura	$4.00 to $4.50
CIG	$3.75 to $4.25
Oil:	
NYMEX	$85.00 to $90.00

* 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.

- For 2011, the Company has hedged approximately 45 percent to 50 percent of its estimated natural gas production and 60 percent to 65 percent of its estimated oil production. For 2012, the Company has hedged 15 percent to 20 percent of its estimated natural gas production and 35 percent to 40 percent of its estimated oil production. The hedges that are in place as of February 14, 2011, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price (Per MMBtu/Bbl)
Natural Gas	Collar	NYMEX	1/11 - 3/11	450,000	$5.62-$6.50
Natural Gas	Swap	HSC	1/11 - 12/11	1,350,500	$8.00
Natural Gas	Swap	NYMEX	1/11 - 12/11	4,015,000	$6.1027
Natural Gas	Swap	NYMEX	1/11 - 12/11	3,650,000	$5.4975
Natural Gas	Swap	NYMEX	1/11 - 12/11	3,650,000	$4.58
Natural Gas	Swap	NYMEX	2/11 - 12/11	3,340,000	$4.70
Natural Gas	Swap	NYMEX	2/11 - 12/11	3,340,000	$4.75
Natural Gas	Swap	NYMEX	4/11 - 10/11	2,140,000	$4.775
Natural Gas	Swap	NYMEX	1/12 - 12/12	3,477,000	$6.27
Natural Gas	Swap	NYMEX	1/12 - 12/12	1,830,000	$5.005
Natural Gas	Swap	NYMEX	1/12 - 12/12	915,000	$5.005
Natural Gas	Swap	NYMEX	1/12 - 12/12	915,000	$5.0125
Crude Oil	Collar	NYMEX	1/11 - 12/11	547,500	$80.00-$94.00
Crude Oil	Collar	NYMEX	1/11 - 12/11	365,000	$80.00-$89.00
Crude Oil	Collar	NYMEX	1/11 - 12/11	182,500	$77.00-$86.45
Crude Oil	Collar	NYMEX	1/11 - 12/11	182,500	$75.00-$88.00
Crude Oil	Swap	NYMEX	1/11 - 12/11	365,000	$81.35
Crude Oil	Swap	NYMEX	1/11 - 12/11	182,500	$85.85
Crude Oil	Put Option	NYMEX	1/11 - 12/11	365,000	$80.00*
Crude Oil	Call Option	NYMEX	3/11 - 12/11	306,000	$103.00*
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$87.80
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$94.50
Crude Oil	Collar	NYMEX	1/12 - 12/12	366,000	$80.00-$98.36
Crude Oil	Collar	NYMEX	1/12 - 12/12	183,000	$85.00-$102.75
Crude Oil	Collar	NYMEX	1/12 - 12/12	183,000	$85.00-$103.00
Crude Oil	Swap	NYMEX	1/12 - 12/12	183,000	$100.10
Crude Oil	Swap	NYMEX	1/12 - 12/12	183,000	$100.00
Natural Gas	Basis Swap	Ventura	1/11 - 3/11	450,000	$0.135
Natural Gas	Basis Swap	CIG	1/11 - 12/11	4,015,000	$0.395
Natural Gas	Basis Swap	Ventura	1/11 - 12/11	3,650,000	$0.15
Natural Gas	Basis Swap	Ventura	2/11 - 12/11	1,670,000	$0.15
Natural Gas	Basis Swap	Ventura	2/11 - 12/11	835,000	$0.16
Natural Gas	Basis Swap	Ventura	2/11 - 12/11	3,340,000	$0.16
Natural Gas	Basis Swap	Ventura	2/11 - 12/11	4,175,000	$0.155
Natural Gas	Basis Swap	CIG	1/12 - 12/12	2,745,000	$0.405
Natural Gas	Basis Swap	CIG	1/12 - 12/12	732,000	$0.41

* Deferred premium of $4.00.

Notes:

· 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; HSC is the Houston Ship Channel hub in southeast Texas which connects to several pipelines.

· For all basis swaps, Index prices are below NYMEX prices and are reported as a positive amount in the Price column.

Construction materials and contracting

- Work backlog as of December 31, 2010, was approximately $420 million, with 94 percent of construction backlog being public work and private representing 6 percent. In the Company's peak earnings year of 2006, private backlog represented 40 percent of construction backlog. Total backlog at December 31, 2009, was $459 million.

- Examples of projects in work backlog include several highway paving projects, airports, bridge work, reclamation and harbor deepening projects.

- The Company was recently identified as the apparent low bidder on the Port of Long Beach expansion. Upon final bid approval, the Company's share of the project for this phase is expected to exceed $30 million. This project is not included in the December 31, 2010, backlog.

- As a result of the continued slow recovery in the residential and commercial markets and uncertainty in federal and state transportation funding, the Company expects overall 2011 volumes and margins to be comparable to 2010.

- However, the Company has several significant multi-year projects it will place bids on in 2011 including a light rail project in Hawaii, work on a Texas military base and a major expansion of a computer chip manufacture facility in Oregon. The Company also expects to place a new asphalt oil terminal into service in late 2011 in Wyoming.

- Federal transportation stimulus of $7.9 billion was directed to states where the Company operates. Of that amount, 63 percent was spent as of year end, with the majority of the remaining $2.9 billion to be spent during the remainder of 2011.

- The Company continues to pursue work related to energy projects, such as wind towers, transmission projects, geothermal and refineries. It is also pursuing opportunities for expansion of its existing business lines including initiatives aimed at capturing additional market share and expansion into new markets.

- The Company has a strong emphasis on operational efficiencies and cost reduction. Selling, general and administrative expenses are down 38 percent in 2010 as compared to 2006, the peak earnings year for this segment.

- As the country’s 6th largest sand and gravel producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

New Accounting Standards

For information regarding new accounting standards, see Item 8 – Note 1.

Critical Accounting Policies Involving Significant Estimates

The Company has prepared its financial statements in conformity with GAAP. 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; aggregate 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.

Natural gas and oil properties
Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The extent, quality and reliability of this data can vary. Other factors used in the reserve estimates are prices, estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

As these estimates change, calculated proved reserves may change. Changes in proved reserve quantities impact the Company's depreciation, depletion and amortization expense since the Company uses the units-of-production method to amortize its natural gas and oil properties. The proved reserves are also used as the basis for the disclosures in Item 8 – Supplementary Financial Information and are the underlying basis of the "ceiling test" for the Company's 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, capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges are used in determining the full-cost ceiling. 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 future noncash write-downs of the Company's natural gas and oil properties.

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 at least annually for goodwill.

Goodwill The Company performs its goodwill impairment testing annually in the fourth quarter. In addition, the test is performed on an interim basis whenever events or circumstances indicate that the carrying amount of goodwill may not be recoverable. Examples of such events or circumstances may include a significant adverse change in business climate, weakness in an industry in which the Company's reporting units operate or recent significant cash or operating losses with expectations that those losses will continue.

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2010, 2009 and 2008, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach.

Under the discounted cash flow method, fair value is based on the estimated future cash flows of each reporting unit, discounted to present value using their respective weighted average cost of capital. Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and peer data for each respective reporting unit.

Long-Lived Assets Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing 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.

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 that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the asset could be different using different estimates and assumptions in the valuation techniques used.

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.

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 GAAP 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. If a loss is anticipated on a contract, the loss is immediately recognized.

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.

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 historical returns, 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 matches forecasted future cash flows of the pension and postretirement plans to a yield curve which consists of a hypothetical portfolio of high-quality corporate bonds with varying maturity dates, 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 estimates that a 25 basis point decrease in the discount rate would increase expense by less than $1 million (after tax) for the year ended December 31, 2010.

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. For additional information on the assumptions used in determining plan costs, please see Item 8 – Note 16.

Income taxes

Income taxes require significant judgments and estimates including the determination of income tax expense, deferred tax assets and liabilities and, if necessary, any valuation allowances that may be required for deferred tax assets and accruals for uncertain tax positions. The effective income tax rate is subject to variability from period to period as a result of changes in federal and state income tax rates and/or changes in tax laws. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states. The Company estimates that a one percent change in the effective tax rate would affect income tax expense by approximately $3.7 million for the year ended December 31, 2010.

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 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 regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

The Company believes its estimates surrounding income taxes are reasonable based on the information that is known when the estimates are made.

Liquidity and Capital Commitments
At December 31, 2010, the Company had cash and cash equivalents of $222.1 million and available capacity of $609.6 million under the outstanding credit facilities of the Company and its subsidiaries.

Cash flows
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 2010 decreased $295.1 million from the comparable prior period. The decrease was primarily due to higher working capital requirements of $238.0 million resulting mainly from decreased cash provided from receivables at the construction businesses and lower cash provided from natural gas costs recoverable through rate adjustments at the natural gas distribution business. In addition, excluding working capital requirements, the Company experienced decreased cash flows from operating activities at the construction and natural gas and oil production businesses, partially offset by increased cash flows from operating activities at the electric and natural gas distribution businesses.

Cash flows provided by operating activities in 2009 increased $60.5 million from the comparable prior period. Lower working capital requirements of $263.6 million were partially offset by lower income before depreciation, depletion and amortization and before the after-tax noncash write-down of natural gas and oil properties, largely the effects of lower commodity prices at the natural gas and oil production business. The lower working capital requirements were largely the result of lower receivables and lower net natural gas costs recoverable through rate adjustments at the natural gas distribution business, as well as lower working capital requirements at the other business segments.

Investing activities Cash flows used in investing activities in 2010 decreased $24.2 million from the comparable prior period due to:

- Proceeds from the sale of the Company's equity method investments in the Brazilian Transmission Lines of $69.1 million

- Higher proceeds from the sale or disposition of properties and other of $49.7 million, largely at the natural gas and oil production business and construction materials and contracting business.

Partially offsetting the decrease in cash flows used in investing activities were increased acquisition-related capital expenditures of $98.4 million, largely due to the acquisition of natural gas properties in the Green River Basin.

Cash flows used in investing activities in 2009 decreased $675.2 million from the comparable prior period due to:

- Lower cash used in connection with acquisitions, net of cash acquired, of $527.1 million, primarily due to the absence of the 2008 acquisitions of Intermountain and natural gas producing properties in east Texas
- Decreased ongoing capital expenditures of $297.8 million, primarily at the natural gas and oil production business

Partially offsetting the decrease in cash flows used in investing activities were lower proceeds from investments of $89.5 million and decreased net proceeds from the sale or disposition of property of $60.2 million, largely at the construction materials and contracting business.

Financing activities Cash flows used in financing activities in 2010 decreased $195.2 million from the comparable prior period, primarily due to lower repayment of short-term borrowings and long-term debt of $94.8 million and $279.2 million, respectively, offset in part by lower issuance of long-term debt of $124.8 million and lower issuance of common stock of $60.2 million. Lower cash used in financing activities reflects the effects of proceeds from the sale of the Company's equity method investments and higher net proceeds from the sale and disposition of property and other, as previously discussed.

Cash flows provided by financing activities in 2009 decreased $559.6 million from the comparable prior period, primarily due to lower issuance of long-term debt and short-term borrowings, higher repayment of long-term debt, partially offset by increased issuance of common stock. Lower cash flows provided by financing activities in 2009 reflects lower ongoing capital expenditures and acquisitions, as well as increased cash provided by operating activities.

Defined benefit pension plans
The Company has qualified noncontributory defined benefit pension plans (Pension Plans) for certain employees. Plan assets consist of investments in equity and fixed-income securities. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to the Pension Plans. Actuarial assumptions include assumptions about the discount rate, expected return on plan assets and rate of future compensation increases as determined by the Company within certain guidelines. At December 31, 2010, the Pension Plans' accumulated benefit obligations exceeded these plans' assets by approximately $96.9 million. Pretax pension expense reflected in the years ended December 31, 2010, 2009 and 2008, was $1.0 million, $8.2 million and $4.6 million, respectively. The Company's pension expense is currently projected to be approximately $6.5 million to $7.0 million in 2011. Funding for the Pension Plans is actuarially determined. The minimum required contributions for 2010, 2009 and 2008 were approximately $6.4 million, $7.3 million and $6.8 million, respectively. For further information on the Company's Pension Plans, see Item 8 – Note 16.

Capital expenditures

The Company's capital expenditures for 2008 through 2010 and as anticipated for 2011 through 2013 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2008	2009	2010	2011	2012	2013
			(In millions)			
Capital expenditures:						
Electric	$73	$115	$86	$76	$79	$114
Natural gas distribution	398	44	75	80	66	54
Construction services	24	13	15	10	10	11
Pipeline and energy services	43	70	14	41	21	125
Natural gas and oil production	711	183	356	306	365	418
Construction materials and contracting	128	27	26	39	43	57
Other	1	3	2	17	1	1
Net proceeds from sale or disposition of property and other	(87)	(27)	(79)	(8)	(2)	—
Net capital expenditures	1,291	428	495	561	583	780
Retirement of long-term debt	201	293	14	73	136	279
	$1,492	$721	$509	$634	$719	$1,059

*The Company continues to evaluate 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.

Capital expenditures for 2010, 2009 and 2008 in the preceding table include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions and the outstanding indebtedness related to the 2008 Intermountain acquisition. The net noncash transactions were $17.5 million in 2010, immaterial in 2009 and $97.6 million in 2008.

In 2010, the Company acquired natural gas properties in the Green River Basin in southwest Wyoming. The total purchase consideration for these properties and purchase price adjustments with respect to certain other acquisitions made prior to 2010, consisting of the Company's common stock and cash, was $106.4 million.

The 2010 capital expenditures, including those for the previously mentioned acquisitions and retirements of long-term debt, were met from internal sources and the issuance of long-term debt and the Company's equity securities. Estimated capital expenditures for the years 2011 through 2013 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline and gathering projects
- Further development of existing properties, acquisition of additional leasehold acreage and exploratory drilling at the natural gas and oil production segment
- Power generation opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- 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. The Company expects the 2011 estimated capital expenditures to be funded in their entirety with cash flow generated from operations. It is anticipated that all of the funds required for capital expenditures and retirement of long-term debt for the years 2012 through 2013 will be met from various sources, including internally generated funds; the Company's credit facilities, 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 later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2010. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued. For additional information on the covenants, certain other conditions and cross-default provisions, see Item 8 – Note 9.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries at December 31, 2010:

Company	Facility	Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
				(Dollars in millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$125.0		$ 20.0	(b)	$—		6/21/11
Cascade Natural Gas Corporation	Revolving credit agreement	$50.0	(c)	$ —		$1.9	(d)	12/28/12 (e)
Intermountain Gas Company	Revolving credit agreement	$65.0	(f)	$ 20.2		$—		8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (g)	$400.0		$ —	(b)	$25.8	(d)	12/13/12
Williston Basin Interstate Pipeline Company	Uncommitted long-term private shelf agreement	$125.0		$ 87.5		$—		12/23/11 (h)

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letters of credit, as discussed in Item 8 – Note 19, reduce amounts available under the credit agreement.
(e) Provisions allow for an extension of up to two years upon consent of the banks.
(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(g) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.
(h) Represents expiration of the ability to borrow additional funds under the agreement.

In order to maintain the Company's and Centennial's respective commercial paper programs in the amounts indicated above, both the Company and Centennial must have revolving credit agreements in place at least equal to the amount of their commercial paper programs. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. The commercial paper borrowings at December 31, 2010, are classified as short-term borrowings and had a weighted average interest rate of .37 percent. The Company's objective

is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a further downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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 become too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

The Company's coverage of fixed charges including preferred stock dividends was 4.1 times for the 12 months ended December 31, 2010. Due to the $384.4 million after-tax noncash write-down of natural gas and oil properties in the first quarter of 2009, earnings were insufficient by $228.7 million to cover fixed charges for the 12 months ended December 31, 2009. If the $384.4 million after-tax noncash write-down is excluded, the coverage of fixed charges including preferred stock dividends would have been 4.6 times for the 12 months ended December 31, 2009.

The coverage of fixed charges including preferred stock dividends, that excludes the effect of the after-tax noncash write-down of natural gas and oil properties is a non-GAAP financial measure. The Company believes that this non-GAAP financial measure is useful because the write-down excluded is not indicative of the Company's cash flows available to meet its fixed charges obligations. The presentation of this additional information is not meant to be considered a substitute for financial measures prepared in accordance with GAAP.

Common stockholders' equity as a percent of total capitalization was 64 percent and 63 percent at December 31, 2010 and 2009, respectively. This ratio is calculated as the Company's common stockholders' equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus stockholders' equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

In September 2008, the Company entered into a Sales Agency Financing Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 5 million shares of the Company's common stock. 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 May 28, 2011. Proceeds from the sale of shares of common stock under the agreement have been and are expected to be used for corporate development purposes and other general corporate purposes. The Company had issued a total of approximately 3.2 million shares of stock under the Sales Agency Financing Agreement in 2009, resulting in total net proceeds of $63.1 million. The Company did not issue any shares of stock in 2010 under the Sales Agency Financing Agreement.

The Company currently has authorization to issue and sell up to $1.0 billion of securities pursuant to a registration statement on file with the SEC. The Company may sell all or a portion of such securities if warranted by market conditions and the Company's capital requirements. Any offer and sale of such securities will be made only by means of a prospectus meeting the requirements of the Securities Act and the rules and regulations thereunder.

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. 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. Centennial's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in Centennial's credit ratings have not limited, nor are currently expected to limit, Centennial's ability to access the capital markets. If Centennial were to experience a further downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the Centennial credit agreement, Centennial expects that it will negotiate the extension or replacement of this agreement, which provides credit support to access the capital markets. In the event Centennial is unable to successfully negotiate this agreement, or in the event the fees on this facility become too expensive, which Centennial does not currently anticipate, it would seek alternative funding.

Off balance sheet arrangements

In connection with the sale of the Brazilian Transmission Lines, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

Centennial continues to guarantee CEM's obligations under a construction contract for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. For more information, see Item 8 – Note 19.

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 19. At December 31, 2010, the Company's commitments under these obligations were as follows:

	2011	2012	2013	2014	2015	Thereafter	Total
				(In millions)			
Long-term debt	$72.8	$136.4	$279.1	$9.2	$266.4	$742.9	$1,506.8
Estimated interest payments*	88.4	84.7	70.1	62.3	58.3	284.9	648.7
Operating leases	25.4	20.3	17.3	9.4	4.3	50.3	127.0
Purchase commitments	497.9	296.5	206.5	110.0	49.9	195.3	1,356.1
	$684.5	$537.9	$573.0	$190.9	$378.9	$1,273.4	$3,638.6

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

Not reflected in the table above are $9.4 million in uncertain tax positions for which the year of settlement is not reasonably possible to determine. For more information, see Item 8 – Note 14.

The Company's minimum funding requirements for its defined benefit pension plans for 2011, which are not reflected in the table above, are $10.8 million. For information on potential contributions above the minimum funding requirements, see Item 8 – Note 16.

The Company's multi-employer plan contributions are based on union employee payroll, which cannot be determined in advance for future periods. The Company may also be required to make additional contributions to its multi-employer plans if they become underfunded. For more information, see Item 1A – Risk Factors and Item 8 – Note 16.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2010, 2009 or 2008.

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.

For more information on derivatives and the Company's derivative policies and procedures, see Item 8 – Notes 1 and 7.

Commodity price risk

Fidelity utilizes derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on forecasted sales of natural gas and oil production. Cascade utilizes, and Intermountain periodically utilizes, derivative instruments to manage a portion of their regulated natural gas supply portfolio in order to manage fluctuations in the price of natural gas.

The following table summarizes derivative agreements entered into by Fidelity and Cascade as of December 31, 2010. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade to receive variable prices and pay fixed prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas swap agreements maturing in 2011	$ 5.69	12,666	$ 14,501
Natural gas swap agreement maturing in 2012	$ 6.27	3,477	$ 4,104
Natural gas basis swap agreements maturing in 2011	$ .27	8,115	$ (256)
Natural gas basis swap agreements maturing in 2012	$ .41	3,477	$ (33)
Oil swap agreements maturing in 2011	$ 82.85	548	$ (5,961)
Cascade			
Natural gas swap agreements maturing in 2011	$ 8.10	2,270	$ (9,359)

	Weighted Average Floor/Ceiling Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas collar agreement maturing in 2011	$5.62/$6.50	450	$ 579
Oil collar agreements maturing in 2011	$78.86/$90.64	1,278	$ (8,319)
Oil collar agreements maturing in 2012	$80.00/$93.55	1,098	$ (6,450)

	Deferred Premium	Weighted Average Floor (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Fidelity				
Oil put agreement maturing in 2011	$4.00	$ 80.00	365	$ (490)

The following table summarizes derivative agreements entered into by Fidelity, Cascade and Intermountain as of December 31, 2009. These agreements call for Fidelity to receive fixed prices and pay variable prices, and for Cascade and Intermountain to receive variable prices and pay fixed prices.

(Forward notional volume and fair value in thousands)

	Weighted Average Fixed Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas swap agreements maturing in 2010	$5.99	21,071	$5,968
Natural gas swap agreement maturing in 2011	$8.00	1,351	$2,377
Natural gas basis swap agreements maturing in 2010	$.24	14,600	$(4,021)
Natural gas basis swap agreement maturing in 2011	$.14	450	$(108)
Oil swap agreements maturing in 2010	$78.13	730	$(3,043)
Cascade			
Natural gas swap agreements maturing in 2010	$8.03	8,922	$(23,058)
Natural gas swap agreements maturing in 2011	$8.10	2,270	$(4,756)
Intermountain			
Natural gas swap agreements maturing in 2010	$6.03	900	$(86)

	Weighted Average Floor/Ceiling Price (Per MMBtu/Bbl)	Forward Notional Volume (MMBtu/Bbl)	Fair Value
Fidelity			
Natural gas collar agreements maturing in 2010	$5.63/$6.25	3,650	$(39)
Natural gas collar agreement maturing in 2011	$5.62/$6.50	450	$(6)
Oil collar agreements maturing in 2010	$65.00/$80.50	730	$(4,867)
Oil collar agreement maturing in 2011	$80.00/$94.00	548	$357

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, 2010 and 2009, 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, 2010.

	2011	2012	2013	2014	2015	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$72.8	$136.4	$258.9	$9.2	$266.4	$ 742.9	$1,486.6	$1,601.0
Weighted average interest rate	7.0 %	5.9 %	6.0 %	6.9 %	5.7 %	6.3 %	6.1 %	—
Variable rate	—	—	$20.2	—	—	—	$20.2	$20.2
Weighted average interest rate	—	—	2.5 %	—	—	—	2.5 %	—

Foreign currency risk

The Company's equity method investment in the Brazilian Transmission Lines is 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, 2010 and 2009, 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) and 15d-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 the Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

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, 2010. 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, 2010.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ Terry D. Hildestad	/s/ Doran N. Schwartz
Terry D. Hildestad	Doran N. Schwartz
President and Chief Executive Officer	Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2010 and 2009, 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, 2010. Our audits also included the financial statement schedules for each of the three years in the period ended December 31, 2010, listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules 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 MDU Resources Group, Inc. and subsidiaries as of December 31, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, the financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, the Company adopted the definitions and required pricing assumptions outlined in the Modernization of Oil and Gas Reporting rules issued by the Securities and Exchange Commission effective as of December 31, 2009.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2010, 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 23, 2011, expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 23, 2011

Report of Independent Registered Public Accounting Firm

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

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2010, 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, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, 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 schedules as of and for the year ended December 31, 2010, of the Company and our report dated February 23, 2011, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 23, 2011

MDU RESOURCES GROUP, INC.
Consolidated Statements of Income

Years ended December 31,	2010	2009	2008
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$1,359,028	$1,504,269	$1,685,199
Construction services, natural gas and oil production, construction materials and contracting, and other	2,550,667	2,672,232	3,318,079
Total operating revenues	3,909,695	4,176,501	5,003,278
Operating expenses:			
Fuel and purchased power	63,065	65,717	75,333
Purchased natural gas sold	567,806	739,678	765,900
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	291,524	263,869	262,053
Construction services, natural gas and oil production, construction materials and contracting, and other	2,084,377	2,143,195	2,686,055
Depreciation, depletion and amortization	328,843	330,542	366,020
Taxes, other than income	163,353	166,597	200,080
Write-down of natural gas and oil properties (Note 1)	—	620,000	135,800
Total operating expenses	3,498,968	4,329,598	4,491,241
Operating income (loss)	410,727	(153,097)	512,037
Earnings from equity method investments	30,816	8,499	6,627
Other income	8,018	9,331	4,012
Interest expense	83,011	84,099	81,527
Income (loss) before income taxes	366,550	(219,366)	441,149
Income taxes	122,530	(96,092)	147,476
Income (loss) from continuing operations	244,020	(123,274)	293,673
Loss from discontinued operations, net of tax (Note 3)	(3,361)	—	—
Net income (loss)	240,659	(123,274)	293,673
Dividends on preferred stocks	685	685	685
Earnings (loss) on common stock	$239,974	$(123,959)	$292,988
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	$1.29	$(.67)	$1.60
Discontinued operations, net of tax	(.01)	—	—
Earnings (loss) per common share – basic	$1.28	$(.67)	$1.60

Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	$1.29	$(.67)	$1.59
Discontinued operations, net of tax	(.02)	—	—
Earnings (loss) per common share – diluted	$1.27	$(.67)	$1.59
Dividends per common share	$.6350	$.6225	$.6000
Weighted average common shares outstanding – basic	188,137	185,175	183,100
Weighted average common shares outstanding – diluted	188,229	185,175	183,807

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

MDU RESOURCES GROUP, INC.
Consolidated Balance Sheets

December 31,	2010	2009
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$222,074	$175,114
Receivables, net	583,743	531,980
Inventories	252,897	249,804
Deferred income taxes	32,890	28,145
Commodity derivative instruments	15,123	7,761
Prepayments and other current assets	60,441	68,854
Total current assets	1,167,168	1,061,658
Investments	103,661	145,416
Property, plant and equipment (Note 1)	7,218,503	6,766,582
Less accumulated depreciation, depletion and amortization	3,103,323	2,872,465
Net property, plant and equipment	4,115,180	3,894,117
Deferred charges and other assets:		
Goodwill (Note 5)	634,633	629,463
Other intangible assets, net (Note 5)	25,271	28,977
Other	257,636	231,321
Total deferred charges and other assets	917,540	889,761
Total assets	$6,303,549	$5,990,952
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings (Note 9)	$20,000	$10,300
Long-term debt due within one year	72,797	12,629
Accounts payable	301,132	281,906
Taxes payable	56,186	55,540
Dividends payable	30,773	29,749
Accrued compensation	40,121	47,425
Commodity derivative instruments	24,428	36,907
Other accrued liabilities	222,639	192,729
Total current liabilities	768,076	667,185
Long-term debt (Note 9)	1,433,955	1,486,677
Deferred credits and other liabilities:		
Deferred income taxes	672,269	590,968
Other liabilities	736,447	674,475
Total deferred credits and other liabilities	1,408,716	1,265,443
Commitments and contingencies (Notes 16, 18 and 19)		
Stockholders' equity:		
Preferred stocks (Note 11)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 12)		
Authorized – 500,000,000 shares, $1.00 par value		
Issued – 188,901,379 shares in 2010 and 188,389,265 shares in 2009	188,901	188,389
Other paid-in capital	1,026,349	1,015,678

Retained earnings	1,497,439	1,377,039
Accumulated other comprehensive loss	(31,261)	(20,833)
Treasury stock at cost – 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,677,802	2,556,647
Total stockholders' equity	2,692,802	2,571,647
Total liabilities and stockholders' equity	$6,303,549	$5,990,952

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, 2010, 2009 and 2008

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Treasury Stock Amount	Total
			(In thousands, except shares)					
Balance at December 31, 2007	182,946,528	$182,947	$912,806	$1,433,585	$(9,393)	(538,921)	$(3,626)	$2,516,319
Comprehensive income:								
Net income	—	—	—	293,673	—	—	—	293,673
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	—	—	—	—	43,448	—	—	43,448
Postretirement liability adjustment	—	—	—	—	(13,751)	—	—	(13,751)
Foreign currency translation adjustment	—	—	—	—	(9,534)	—	—	(9,534)
Total comprehensive income	—	—	—	—	—	—	—	313,836
Fair value option transition adjustment	—	—	—	405	(405)	—	—	—
Dividends on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends on common stock	—	—	—	(110,148)	—	—	—	(110,148)
Tax benefit on stock-based compensation	—	—	4,441	—	—	—	—	4,441
Issuance of common stock	1,261,755	1,261	21,052	—	—	—	—	22,313

Balance at December 31, 2008	184,208,283	184,208	938,299	1,616,830	10,365	(538,921)	(3,626)	2,746,076
Comprehensive loss:								
Net loss	—	—	—	(123,274)	—	—	—	(123,274)
Other comprehensive income (loss), net of tax -								
Net unrealized loss on derivative instruments qualifying as hedges	—	—	—	—	(51,684)	—	—	(51,684)
Postretirement liability adjustment	—	—	—	—	9,918	—	—	9,918
Foreign currency translation adjustment	—	—	—	—	10,568	—	—	10,568
Total comprehensive loss	—	—	—	—	—	—	—	(154,472)
Dividends on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends on common stock	—	—	—	(115,832)	—	—	—	(115,832)
Tax benefit on stock-based compensation	—	—	(117)	—	—	—	—	(117)
Issuance of common stock	4,180,982	4,181	77,496	—	—	—	—	81,677
Balance at December 31, 2009	188,389,265	188,389	1,015,678	1,377,039	(20,833)	(538,921)	(3,626)	2,556,647
Comprehensive income:								
Net income	—	—	—	240,659	—	—	—	240,659
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	—	—	—	—	673	—	—	673

Postretirement liability adjustment	—	—	—	—	(5,730)	—	—	(5,730)
Foreign currency translation adjustment	—	—	—	—	(5,371)	—	—	(5,371)
Total comprehensive income	—	—	—	—	—	—	—	230,231
Dividends on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends on common stock	—	—	—	(119,574)	—	—	—	(119,574)
Tax benefit on stock-based compensation	—	—	924	—	—	—	—	924
Issuance of common stock	512,114	512	9,747	—	—	—	—	10,259
Balance at December 31, 2010	188,901,379	$188,901	$1,026,349	$1,497,439	$ (31,261)	(538,921)	$(3,626)	$2,677,802

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,	2010	2009	2008
		(In thousands)	
Operating activities:			
Net income (loss)	$240,659	$(123,274)	$293,673
Loss from discontinued operations, net of tax	(3,361)	—	—
Income (loss) from continuing operations	244,020	(123,274)	293,673
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	328,843	330,542	366,020
Earnings, net of distributions, from equity method investments	(26,158)	(3,018)	365
Deferred income taxes	66,585	(169,764)	64,890
Write-down of natural gas and oil properties (Note 1)	—	620,000	135,800
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(59,037)	132,939	27,165
Inventories	(4,728)	13,969	(18,574)
Other current assets	(7,424)	67,803	(64,771)
Accounts payable	17,833	(61,867)	28,205
Other current liabilities	12,289	44,039	(38,738)
Other noncurrent changes	(20,271)	(4,683)	(7,848)
Net cash provided by continuing operations	551,952	846,686	786,187
Net cash used in discontinued operations	(319)	—	—
Net cash provided by operating activities	551,633	846,686	786,187
Investing activities:			
Capital expenditures	(449,282)	(448,675)	(746,478)
Acquisitions, net of cash acquired	(104,812)	(6,410)	(533,543)
Net proceeds from sale or disposition of property and other	76,386	26,679	86,927
Investments	704	(3,740)	85,773
Proceeds from sale of equity method investments	69,060	—	—
Net cash used in continuing operations	(407,944)	(432,146)	(1,107,321)
Net cash provided by discontinued operations	—	—	—
Net cash used in investing activities	(407,944)	(432,146)	(1,107,321)
Financing activities:			
Issuance of short-term borrowings	20,000	10,300	216,400
Repayment of short-term borrowings	(10,300)	(105,100)	(113,000)
Issuance of long-term debt	20,200	145,000	453,929
Repayment of long-term debt	(13,668)	(292,907)	(200,527)
Proceeds from issuance of common stock	4,972	65,207	15,011
Dividends paid	(119,157)	(115,023)	(108,591)
Tax benefit on stock-based compensation	1,186	601	4,441
Net cash provided by (used in) continuing operations	(96,767)	(291,922)	267,663
Net cash provided by discontinued operations	—	—	—
Net cash provided by (used in) financing activities	(96,767)	(291,922)	267,663
Effect of exchange rate changes on cash and cash equivalents	38	782	(635)

Increase (decrease) in cash and cash equivalents	46,960	123,400	(54,106)
Cash and cash equivalents – beginning of year	175,114	51,714	105,820
Cash and cash equivalents – end of year	$222,074	$175,114	$51,714

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 contracting, 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 contracting, 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 jointly owned electric generating facilities.

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 regulatory accounting, which 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.

Depreciation, depletion and amortization expense is reported separately on the Consolidated Statements of Income and therefore is excluded from the other line items within operating expenses.

Management has also evaluated the impact of events occurring after December 31, 2010, up to the date of issuance of these consolidated financial statements.

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.

Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $21.6 million as of December 31, 2010. For more information, see percentage-of-completion method in this note.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2010 and 2009, was $15.3 million and $16.6 million, respectively.

Inventories and natural gas in storage
Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be used within one year was included in inventories. Inventories at December 31 consisted of:

	2010	2009
	(In thousands)	
Aggregates held for resale	$ 79,894	$ 80,087
Materials and supplies	57,324	58,095
Natural gas in storage (current)	34,557	35,619
Merchandise for resale	30,182	29,323
Asphalt oil	25,234	22,989
Other	25,706	23,691
Total	$ 252,897	$ 249,804

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $48.0 million and $59.6 million at December 31, 2010 and 2009, respectively.

Investments
The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, investments in fixed-income and equity securities and auction rate securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company has elected to measure its investments in certain fixed-income and equity securities at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. These investments had previously been accounted for as available-for-sale investments and were recorded at fair value with any unrealized gains and losses, net of income taxes, recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets until realized. The Company accounts for auction rate securities as available-for-sale. For more information, see Notes 8 and 16.

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 $17.6 million, $17.4 million and $9.5 million in 2010, 2009 and 2008, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and natural gas and oil production properties, which are amortized on the units-of-production method based on total reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

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

	2010	2009	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$538,071	$486,710	48
Distribution	243,205	230,795	36
Transmission	161,972	146,373	44
Other	83,786	77,913	12
Natural gas distribution:			
Distribution	1,223,239	1,218,124	38
Other	285,606	238,084	21
Pipeline and energy services:			
Transmission	357,395	351,019	52
Gathering	41,931	41,815	19
Storage	33,967	33,701	53
Other	33,938	33,283	27
Nonregulated:			
Construction services:			
Land	4,526	4,526	—
Buildings and improvements	14,101	15,110	24
Machinery, vehicles and equipment	94,252	87,462	7
Other	10,061	9,138	4
Pipeline and energy services:			
Gathering	203,064	202,467	17
Other	13,512	12,914	10
Natural gas and oil production:			
Natural gas and oil properties	2,320,967	1,993,594	*
Other	35,971	35,200	9
Construction materials and contracting:			
Land	124,018	127,928	—
Buildings and improvements	65,003	65,778	20
Machinery, vehicles and equipment	899,365	925,747	12
Construction in progress	4,879	3,733	—
Aggregate reserves	393,110	391,803	**
Other:			
Land	2,837	2,942	—
Other	29,727	30,423	16
Less accumulated depreciation, depletion and amortization	3,103,323	2,872,465	
Net property, plant and equipment	$4,115,180	$3,894,117	

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $1.77, $1.64 and $2.00 for the years ended December 31, 2010, 2009 and 2008, respectively. Includes natural gas and oil production properties accounted for under the full-cost method, of which $182.4 million and $178.2 million were excluded from amortization at December 31, 2010 and 2009, respectively.

** Depleted on the units-of-production method.

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. No significant impairment losses were recorded in 2010, 2009 and 2008. Unforeseen events and changes in circumstances could require the recognition of 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, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach. If the fair value of a reporting unit is less than its carrying value, step two of the goodwill impairment test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2010, 2009 and 2008, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded. For more information on goodwill, see Note 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 cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, 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 regardless of subsequent price changes.

Due to low natural gas and oil prices that existed on March 31, 2009, and December 31, 2008, the Company's capitalized costs under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2009, and December 31, 2008. Accordingly, the Company was required to write down its natural gas and oil producing properties. The noncash write-downs amounted to $620.0 million and $135.8 million ($384.4 million and $84.2 million after tax) for the years ended December 31, 2009 and 2008, respectively.

The Company hedges a portion of its natural gas and oil production and the effects of the cash flow hedges were used in determining the full-cost ceiling. The Company would have recognized additional write-downs of its natural gas and oil properties of $107.9 million ($66.9 million after tax) at March 31, 2009, and $79.2 million ($49.1 million after tax) at December 31, 2008, if the effects of cash flow hedges had not been considered in calculating the full-cost ceiling. For more information on the Company's cash flow hedges, see Note 7.

At December 31, 2010, 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, 2010, 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, 2010, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2010	2009	2008	2007 and prior
			(In thousands)		
Acquisition	$151,404	$74,710	$1,684	$47,139	$27,871
Development	9,258	7,936	245	515	562
Exploration	15,401	12,472	430	2,496	3
Capitalized interest	6,339	3,425	85	1,806	1,023
Total costs not subject to amortization	$182,402	$98,543	$2,444	$51,956	$29,459

Costs not subject to amortization as of December 31, 2010, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Niobrara play, east Texas properties, the Paradox Basin, the Green River Basin and the Big Horn Basin. 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. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $87.3 million and $92.6 million at December 31, 2010 and 2009, respectively. 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 properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

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 and estimated earnings in excess of billings on uncompleted contracts of $46.6 million and $28.8 million at December 31, 2010 and 2009, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $65.2 million and $49.3 million at December 31, 2010 and 2009, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $51.1 million and $45.4 million at December 31, 2010 and 2009, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $50.4 million and $44.0 million at December 31, 2010 and 2009, respectively. The long-term retainage which was included in deferred charges and other assets – other was $700,000 and $1.4 million at December 31, 2010 and 2009, respectively.

Derivative instruments

The Company's policy allows the use of derivative instruments as part of an overall energy price, foreign currency and interest rate risk management program to efficiently manage and minimize commodity price, foreign currency and interest rate risk. The Company's policy prohibits the use of derivative instruments for speculating to take advantage of market trends and conditions, and the Company has procedures in place to monitor compliance with its policies. The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties.

The Company's policy generally allows the hedging of monthly forecasted sales of natural gas and oil production at Fidelity for a period up to 36 months from the time the Company enters into the hedge. The Company's policy requires that 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 allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical natural gas and oil production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain 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. 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.

The Company's swap, collar and put option agreements are reflected at fair value, based upon futures prices, volatility and time to maturity, among other things.

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.

Legal costs
The Company expenses external legal fees as they are incurred.

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 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $37.0 million and $37.4 million at December 31, 2010 and 2009, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $6.6 million and $982,000 at December 31, 2010 and 2009, respectively, which is included in prepayments and other current assets.

Insurance
Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $1 million per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $1 million per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made and reported 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 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 regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

Tax positions taken or expected to be taken in an income tax return are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than 50 percent likely of being realized upon ultimate settlement with a taxing authority. The Company recognizes interest and penalties accrued related to unrecognized tax benefits in income taxes.

Foreign currency translation adjustment

The functional currency of the Company's investment in the Brazilian Transmission Lines, 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.

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) 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. In 2010 and 2008, there were no shares excluded from the calculation of diluted earnings per share. Diluted loss per common share for 2009 was computed by dividing the loss on common stock by the weighted average number of shares of common stock outstanding during the year. Due to the loss on common stock for 2009, 824,871 outstanding stock options, 17,636 restricted stock grants and 656,570 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive. Common stock outstanding includes issued shares less shares held in treasury.

Use of estimates

The preparation of financial statements in conformity with GAAP 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; aggregate 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,	2010	2009	2008
		(In thousands)	
Interest, net of amount capitalized	$80,962	$81,267	$77,152
Income taxes	$46,892	$39,807	$113,212

New accounting standards
Improving Disclosure About Fair Value Measurements In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. The guidance requires additional disclosures but does not impact the Company's financial position or results of operations.

Comprehensive income (loss)
Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive income (loss) resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement 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, were as follows:

	2010	2009	2008
		(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 $(1,867), $(2,509) and $30,414 in 2010, 2009 and 2008, respectively	$(3,077)	$(4,094)	$49,623
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $(2,305), $29,170 and $3,795 in 2010, 2009 and 2008, respectively	(3,750)	47,590	6,175
Net unrealized gain (loss) on derivative instruments qualifying as hedges	673	(51,684)	43,448
Postretirement liability adjustment, net of tax of $(3,609), $6,291 and $(8,750) in 2010, 2009 and 2008, respectively	(5,730)	9,918	(13,751)
Foreign currency translation adjustment, net of tax of $(3,486), $6,814 and $(6,108) in 2010, 2009 and 2008, respectively	(5,371)	10,568	(9,534)
Total other comprehensive income (loss)	$(10,428)	$(31,198)	$20,163

The after-tax components of accumulated other comprehensive income (loss) as of December 31, 2010, 2009 and 2008, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Total Accumulated Other Comprehensive Income (Loss)
		(In thousands)		
Balance at December 31, 2008	$49,386	$ (35,081)	$(3,940)	$ 10,365
Balance at December 31, 2009	$(2,298)	$ (25,163)	$6,628	$ (20,833)
Balance at December 31, 2010	$(1,625)	$ (30,893)	$1,257	$ (31,261)

Note 2 – Acquisitions

In 2010, the Company acquired natural gas properties in the Green River Basin in southwest Wyoming. The acquisition includes the purchase of 61 Bcfe of proven reserves. The total purchase consideration for these properties and purchase price adjustments with respect to certain other acquisitions made prior to 2010, consisting of the Company's common stock and cash, was $106.4 million.

In 2009, the Company acquired a pipeline and energy services business in Montana which was not material. The total purchase consideration for this business and purchase price adjustments with respect to certain other acquisitions made prior to 2009, consisting of the Company's common stock and cash, was $22.0 million.

In 2008, the Company acquired a construction services business in Nevada; natural gas properties in Texas; construction materials and contracting businesses in Alaska, California, Idaho and Texas; and Intermountain, a natural gas distribution business, as discussed below. The total purchase consideration for these businesses and properties and purchase price adjustments with respect to certain other acquisitions made prior to 2008, consisting of the Company's common stock and cash and the outstanding indebtedness of Intermountain, was $624.5 million.

On October 1, 2008, the acquisition of Intermountain was finalized and Intermountain became an indirect wholly owned subsidiary of the Company. Intermountain's service area is in Idaho.

The above acquisitions were accounted for under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. 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 3 – Discontinued Operations
In 2007, Centennial Resources sold CEM to Bicent Power LLC. In connection with the sale, Centennial Resources agreed to indemnify Bicent Power LLC and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. The Company incurred legal expenses related to this matter, and established a reserve for an indemnification claim by Bicent Power LLC, which are reflected as discontinued operations in the consolidated financial statements and accompanying notes in 2010. Discontinued operations are included in the Other category. For further information, see Note 19.

Note 4 – Equity Method Investments
Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2010 and 2009, include the Brazilian Transmission Lines.

In August 2006, MDU Brasil acquired ownership interests in companies owning the Brazilian Transmission Lines. The interests involve the ENTE, ERTE and ECTE 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. Alusa and CEMIG hold the remaining ownership interests, with CELESC also having an ownership interest in ECTE. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In the fourth quarter of 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. On November 12, 2010, the Company completed the sale and recognized a gain of $22.7 million ($13.8 million after tax) which is recorded in earnings from equity method investments on the Consolidated Statements of Income. The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. One of the parties will purchase the Company's remaining ownership interests in ECTE over a four-year period.

At December 31, 2010 and 2009, the investments in which the Company held an equity method interest had total assets of $107.4 million and $387.0 million, respectively, and long-term debt of $30.1 million and $176.7 million, respectively. The Company's investment in its equity method investments was approximately $10.9 million and $62.4 million, including undistributed earnings of $1.9 million and $9.3 million, at December 31, 2010 and 2009, respectively.

Note 5 – Goodwill and Other Intangible Assets
The changes in the carrying amount of goodwill for the year ended December 31, 2010, were as follows:

	Balance as of January 1, 2010*	Goodwill Acquired During the Year**	Balance as of December 31, 2010*
		(In thousands)	
Electric	$—	$—	$—
Natural gas distribution	345,736	—	345,736
Construction services	100,127	2,743	102,870
Pipeline and energy services	7,857	1,880	9,737
Natural gas and oil production	—	—	—
Construction materials and contracting	175,743	547	176,290
Other	—	—	—
Total	$629,463	$5,170	$634,633

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.
** 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, 2009, were as follows:

	Balance as of January 1, 2009*	Goodwill Acquired During the Year**	Balance as of December 31, 2009*
		(In thousands)	
Electric	$—	$—	$—
Natural gas distribution	344,952	784	345,736
Construction services	95,619	4,508	100,127
Pipeline and energy services	1,159	6,698	7,857
Natural gas and oil production	—	—	—
Construction materials and contracting	174,005	1,738	175,743
Other	—	—	—
Total	$615,735	$13,728	$629,463

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and energy services segment, which occurred in prior periods.
** Includes purchase price adjustments that were not material related to acquisitions in a prior period.

Other amortizable intangible assets at December 31 were as follows:

	2010	2009
	(In thousands)	
Customer relationships	$ 24,942	$ 24,942
Accumulated amortization	(11,625)	(9,500)
	13,317	15,442
Noncompete agreements	9,405	12,377
Accumulated amortization	(6,425)	(6,675)
	2,980	5,702
Other	13,217	10,859
Accumulated amortization	(4,243)	(3,026)
	8,974	7,833
Total	$ 25,271	$ 28,977

Amortization expense for intangible assets for the years ended December 31, 2010, 2009 and 2008, was $4.2 million, $5.0 million and $5.1 million, respectively. Estimated amortization expense for intangible assets is $4.1 million in 2011, $4.0 million in 2012, $3.8 million in 2013, $3.2 million in 2014, $2.6 million in 2015 and $7.6 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:

	Estimated Recovery Period *	2010	2009
		(In thousands)	
Regulatory assets:			
Deferred income taxes	**	$ 114,427	$ 85,712
Pension and postretirement benefits (a)	(e)	103,818	91,078
Costs related to identifying generation development (a)	Up to 3 years	13,777	15,499
Taxes recoverable from customers (a)	Up to 50 years	11,961	10,102
Long-term debt refinancing costs (a)	Up to 22 years	11,101	12,089
Plant costs (a)	Over plant lives	9,964	7,775
Natural gas supply derivatives (b)	Up to 2 years	9,359	27,900
Natural gas cost recoverable through rate adjustments (b)	Up to 28 months	6,609	982
Other (a) (b)	Largely within 1 year	35,225	12,242
Total regulatory assets		316,241	263,379
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		276,652	251,143
Deferred income taxes**		64,017	53,835
Natural gas costs refundable through rate adjustments (d)		36,996	37,356
Taxes refundable to customers (c)		19,352	34,571
Other (c) (d)		16,080	17,767

Total regulatory liabilities		413,097		394,672
Net regulatory position	$	(96,856)	$	(131,293)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
** Represents deferred income taxes related to regulatory assets and liabilities.
(a) Included in deferred charges and other assets on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in other liabilities on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of

December 31, 2010, approximately $35.4 million of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting 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 regulatory accounting 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. The Company's policy is to not offset fair value amounts for derivative instruments, and as a result the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. 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, 2010, the Company had no outstanding foreign currency or interest rate hedges.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2010, credit risk was not material.

Cascade and Intermountain
At December 31, 2010, Cascade held natural gas swap agreements with total forward notional volumes of 2.3 million MMBtu, which were not designated as hedges. Cascade utilizes, and Intermountain periodically utilizes, natural gas swap agreements to manage a portion of their regulated natural gas supply portfolios in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Periodic changes in the fair market value of the derivative instruments are recorded on the Consolidated Balance Sheets as a

regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the years ended December 31, 2010 and 2009, the change in the fair market value of the derivative instruments of $18.5 million and $61.9 million, respectively, were recorded as a decrease to regulatory assets.

Certain of Cascade's derivative instruments contain credit-risk-related contingent features that permit the counterparties to require collateralization if Cascade's derivative liability positions exceed certain dollar thresholds. The dollar thresholds in certain of Cascade's agreements are determined and may fluctuate based on Cascade's credit rating on its debt. In addition, Cascade's derivative instruments contain cross-default provisions that state if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of such entity's derivative instruments in liability positions. The aggregate fair value of Cascade derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2010, was $9.4 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2010, was $9.4 million.

Fidelity

At December 31, 2010, Fidelity held natural gas swap and collar agreements with total forward notional volumes of 16.6 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 11.6 million MMBtu, and oil swap, collar and put option agreements with total forward notional volumes of 3.3 million Bbl, all of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

The fair value of the derivative 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 and oil 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 received for natural gas and oil production are generally based on market prices.

For the years ended December 31, 2010, 2009 and 2008, the amount of hedge ineffectiveness was immaterial, and there were no components of the derivative instruments' gain or loss excluded 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 operating revenues on the Consolidated Statements of Income. For further information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see Note 1.

As of December 31, 2010, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months. The Company estimates that over the next 12 months net gains of approximately $34,000 (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.

Certain of Fidelity's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2010, was $21.6 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2010, was $21.6 million.

The location and fair value of all of the Company's derivative instruments on the Consolidated Balance Sheets were as follows:

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2010	Fair Value at December 31, 2009
		(In thousands)	
Designated as hedges	Commodity derivative instruments	$15,123	$ 7,761
	Other assets – noncurrent	4,104	2,734
		19,227	10,495
Not designated as hedges	Commodity derivative instruments	—	—
	Other assets – noncurrent	—	—
		—	—
Total asset derivatives		$19,227	$ 10,495

Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2010	Fair Value at December 31, 2009
		(In thousands)	
Designated as hedges	Commodity derivative instruments	$15,069	$ 13,763
	Other liabilities – noncurrent	6,483	114
		21,552	13,877
Not designated as hedges	Commodity derivative instruments	9,359	23,144
	Other liabilities – noncurrent	—	4,756
		9,359	27,900
Total liability derivatives		$30,911	$ 41,777

Note 8 – Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $39.5 million and $34.8 million as of December 31, 2010 and 2009, respectively, are classified as Investments on the Consolidated Balance Sheets. The increase in the fair value of these investments for the year ended December 31, 2010, was $5.8 million (before tax). The increase in the fair value of these investments for the year ended December 31, 2009, was $7.1 million (before tax). The decrease in the fair value of these investments for the year ended December 31, 2008, was $8.6 million (before tax). The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income. The Company did not elect the fair value option for its remaining available-for-sale securities, which are auction rate securities. The Company's auction rate securities, which totaled $11.4 million at December 31, 2010 and 2009, are accounted for as available-for-sale and are recorded at fair value. The fair value of the auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments.

Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in an orderly transaction between market participants at the measurement date. The ASC establishes a hierarchy for grouping assets and liabilities, based on the significance of inputs. The Company's assets and liabilities measured at fair value on a recurring basis are as follows:

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Money market funds	$—	$166,620	$ —	$ 166,620
Available-for-sale securities:				
Fixed-income securities	—	11,400	—	11,400
Insurance investment contract*	—	39,541	—	39,541
Commodity derivative instruments – current	—	15,123	—	15,123
Commodity derivative instruments – noncurrent	—	4,104	—	4,104
Total assets measured at fair value	$—	$236,788	$ —	$ 236,788
Liabilities:				
Commodity derivative instruments – current	$—	$24,428	$ —	$ 24,428
Commodity derivative instruments – noncurrent	—	6,483	—	6,483
Total liabilities measured at fair value	$—	$30,911	$ —	$ 30,911

* The insurance investment contract invests approximately 35 percent in common stock of mid-cap companies, 33 percent in common stock of small-cap companies, 31 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

	Fair Value Measurements at December 31, 2009, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2009
	(In thousands)			
Assets:				
Money market funds	$9,124	$151,000	$ —	$ 160,124
Available-for-sale securities	9,078	37,141	—	46,219
Commodity derivative instruments – current	—	7,761	—	7,761
Commodity derivative instruments – noncurrent	—	2,734	—	2,734
Total assets measured at fair value	$18,202	$198,636	$ —	$ 216,838
Liabilities:				
Commodity derivative instruments – current	$—	$36,907	$ —	$ 36,907
Commodity derivative instruments – noncurrent	—	4,870	—	4,870
Total liabilities measured at fair value	$—	$41,777	$ —	$ 41,777

The estimated fair value of the Company's Level 1 money market funds is determined using the market approach and is valued at the net asset value of shares held by the Company, based on published market quotations in active markets.

The estimated fair value of the Company's Level 1 available-for-sale securities is determined using the market approach and is based on quoted market prices in active markets for identical equity and fixed-income securities.

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions.

The estimated fair value of the Company's Level 2 commodity derivative instruments is based upon futures prices, volatility and time to maturity, among other things. Counterparty statements are utilized to determine the value of the commodity derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the year ended December 31, 2010, there were no significant transfers between Levels 1 and 2.

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The estimated fair value of the Company's long-term debt was based on quoted market prices of the same or similar issues. The estimated fair value of the Company's long-term debt at December 31 was as follows:

	2010		2009	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$1,506,752	$1,621,184	$1,499,306	$1,566,331

The carrying amounts of the Company's remaining financial instruments included in current assets and current liabilities approximate their fair values.

Note 9 – Debt

Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2010. In the event the Company and its subsidiaries do not comply with the applicable covenants and other conditions, alternative sources of funding may need to be pursued.

The following table summarizes the outstanding credit facilities of the Company and its subsidiaries:

Company	Facility	Facility Limit		Amount Outstanding at December 31, 2010		Amount Outstanding at December 31, 2009		Letters of Credit at December 31, 2010		Expiration Date
		(Dollars in millions)								
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$125.0		$ 20.0	(b)	$ —	(b)	$ —		6/21/11
Cascade Natural Gas Corporation	Revolving credit agreement	$50.0	(c)	$ —		$ —		$ 1.9	(d)	12/28/12 (e)
Intermountain Gas Company	Revolving credit agreement	$65.0	(f)	$ 20.2		$ 10.3		$ —		8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (g)	$400.0		$ —	(b)	$ —	(b)	$ 25.8	(d)	12/13/12
Williston Basin Interstate Pipeline Company	Uncommitted long-term private shelf agreement	$125.0		$ 87.5		$ 87.5		$ —		12/23/11 (h)

(a)

The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.

(b) Amount outstanding under commercial paper program.

(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.

(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.

(e) Provisions allow for an extension of up to two years upon consent of the banks.

(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.

(g) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.

(h) Represents expiration of the ability to borrow additional funds under the agreement.

In order to maintain the Company's and Centennial's respective commercial paper programs in the amounts indicated previously, both the Company and Centennial must have revolving credit agreements in place at least equal to the amount of their commercial paper programs. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements.

The following includes information related to the preceding table.

Short-term borrowings
MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. The weighted average interest rate for commercial paper borrowings outstanding at December 31, 2010, was .37 percent.

The Company's credit agreement contains customary covenants and provisions, including covenants of the Company 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.

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

Cascade Natural Gas Corporation Any borrowings under the $50 million revolving credit agreement would be classified as short-term borrowings as Cascade intends to repay the borrowings within one year.

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade 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, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Long-term debt
Intermountain Gas Company The credit agreement contains customary covenants and provisions, including covenants of Intermountain not to permit, as of the end of any fiscal quarter, the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

Intermountain's credit agreement contains cross-default provisions. These provisions state that if (i) Intermountain fails to make any payment with respect to any indebtedness or guarantee in excess of a specified amount, (ii) any other event occurs that would permit the holders of indebtedness or the beneficiaries of guarantees to become payable, or (iii) certain conditions result in an early termination date under any swap contract that is in excess of $10 million, then Intermountain shall be in default under the revolving credit agreement.

MDU Energy Capital, LLC The ability to request additional borrowings under the master shelf agreement expired in August 2010; however, there is debt outstanding that is reflected in the table below. The borrowings under this agreement mature on dates ranging from October 22, 2012 to August 31, 2017. The master shelf agreement contains customary covenants and provisions, including covenants of MDU Energy Capital not to permit (A) the ratio of its total debt (on a consolidated basis) to adjusted total capitalization to be greater than 70 percent, or (B) the ratio of subsidiary debt to subsidiary capitalization to be greater than 65 percent, or (C) the ratio of Intermountain’s total debt (determined on a consolidated basis) to total capitalization to be greater than 65 percent. The agreement also includes a covenant requiring the ratio of MDU Energy Capital earnings before interest and taxes to interest expense (on a consolidated basis), for the 12-month period ended each fiscal quarter, to be greater than 1.5 to 1. In addition, payment obligations under the master shelf agreement may be accelerated upon the occurrence of an event of default (as described in the agreement).

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. 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.

Centennial's credit agreement and certain debt outstanding under an uncommitted long-term master shelf agreement contain customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, 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 master shelf agreement). The master shelf agreement also includes 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 1.75 to 1. 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.

Pursuant to a covenant under the credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. The write-down of the natural gas and oil properties in 2009 would have negatively affected Centennial's ability to make distributions to the Company in 2010, however, in November 2009, the lenders under the credit agreement consented to permit Centennial to make distributions during 2010 in an aggregate amount up to 100 percent of its consolidated net income after taxes during fiscal year 2009 without giving effect to the write-down.

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 practices limit the amount of subsidiary indebtedness.

Williston Basin Interstate Pipeline Company The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of Williston Basin 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.

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

	2010	2009
	(In thousands)	
Senior Notes at a weighted average rate of 6.07%, due on dates ranging from March 29, 2011 to March 8, 2037	$1,358,848	$1,370,455
Medium-Term Notes at a weighted average rate of 7.72%, due on dates ranging from September 4, 2012 to March 16, 2029	81,000	81,000
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	41,189	42,070
Credit agreements at a weighted average rate of 3.04%, due on dates ranging from January 26, 2011 to November 30, 2038	25,715	5,781
Total long-term debt	1,506,752	1,499,306
Less current maturities	72,797	12,629
Net long-term debt	$1,433,955	$1,486,677

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2010, aggregate $72.8 million in 2011; $136.4 million in 2012; $279.1 million in 2013; $9.2 million in 2014; $266.4 million in 2015 and $742.9 million thereafter.

Note 10 – Asset Retirement Obligations
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, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations.

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

	2010	2009
	(In thousands)	
Balance at beginning of year	$ 76,359	$ 70,147
Liabilities incurred	8,608	2,418
Liabilities acquired	5,272	—
Liabilities settled	(10,740)	(9,319)
Accretion expense	3,588	3,385
Revisions in estimates	12,621	9,548
Other	262	180
Balance at end of year	$ 95,970	$ 76,359

The Company believes that any expenses related to asset retirement obligations at the Company's 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, 2010 and 2009, was $5.7 million and $5.9 million, respectively.

Note 11 – Preferred Stocks
Preferred stocks at December 31 were as follows:

	2010	2009
	(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
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 October 1, 2008 through October 21, 2008, the Stock Purchase Plan and K-Plan, with respect to Company stock, were funded with shares of authorized but unissued common stock. From January 2008 through September 30, 2008, and October 22, 2008 through December 2010, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2010, there were 23.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. The most restrictive limitations are discussed below.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to 100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.1 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $147 million of the Company's (excluding its subsidiaries) net assets would be restricted from use for dividend payments. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 – Stock-Based Compensation
The Company has several stock-based compensation plans and is authorized to grant options, restricted stock and stock for up to 14.5 million shares of common stock and has granted options, restricted stock and stock of 5.8 million shares through December 31, 2010. 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 was $3.4 million, net of income taxes of $2.1 million in 2010; $3.4 million, net of income taxes of $2.2 million in 2009; and $3.7 million, net of income taxes of $2.3 million in 2008.

As of December 31, 2010, total remaining unrecognized compensation expense related to stock-based compensation was approximately $4.5 million (before income taxes) which will be amortized over a weighted average period of 1.5 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, 2010, and changes during the year then ended was as follows:

	Number of Shares	Weighted Average Exercise Price
Balance at beginning of year	824,871	$ 13.42
Forfeited	(14,401)	13.22
Exercised	(369,486)	13.53
Balance at end of year	440,984	13.34
Exercisable at end of year	440,984	$ 13.34

Summarized information about stock options outstanding and exercisable as of December 31, 2010, was as follows:

		Options Outstanding and Options Exercisable		
Range of Exercisable Prices	Number Outstanding and Exercisable	Remaining Contractual Life in Years	Weighted Average Exercise Price	Aggregate Intrinsic Value (000's)
$ 11.53 – 14.25	422,599	.2	$ 13.20	$ 2,988
14.26 – 17.13	18,385	.3	16.54	68
Balance at end of year	440,984	.2	$ 13.34	$ 3,056

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, 2010, which would have been received by the option holders had all option holders exercised their options as of that date.

The Company received cash of $5.0 million, $2.1 million and $5.9 million from the exercise of stock options for the years ended December 31, 2010, 2009 and 2008, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2010, 2009 and 2008, was $2.6 million, $1.3 million and $8.1 million, respectively.

Restricted stock awards
Prior to 2002, the Company granted restricted stock awards under a long-term incentive plan. The restricted stock awards vested at various times ranging from one year to nine years from the date of issuance, but certain grants vested early based upon the attainment of certain performance goals. 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, 2010, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	17,636	$ 13.22
Vested	(17,636)	13.22
Nonvested at end of period	—	$ —

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 43,128 shares with a fair value of $849,000, 49,649 shares with a fair value of $879,000 and 45,675 shares with a fair value of $1.2 million issued under this plan during the years ended December 31, 2010, 2009 and 2008, respectively.

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, 2010, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2008	2008-2010	183,102
February 2009	2009-2011	258,757
March 2010	2010-2012	227,826

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, 2010, 2009 and 2008, was $17.40, $20.39 and $30.71, per share, respectively. The grant-date fair value for the performance shares was determined by Monte Carlo simulation using a blended volatility term structure in the range of 25.69 percent to 35.36 percent in 2010, 40.40 percent to 50.98 percent in 2009 and 21.54 percent to 22.97 percent in 2008 comprised of 50 percent historical volatility and 50 percent implied volatility and a risk-free interest rate term structure in the range of .13 percent to 1.45 percent in 2010, .30 percent to 1.36 percent in 2009 and 1.87 percent to 2.23 percent in 2008 based on U.S. Treasury security rates in effect as of the grant date. In addition, the mean overall simulation paths of the discounted dividends expected to be earned in the performance period used in the valuation was $1.04, $1.79 and $1.64 per target share for the 2010, 2009 and 2008 awards, respectively. The fair value of performance share awards that vested during the years ended December 31, 2010, 2009 and 2008, was $3.5 million, $2.8 million and $8.5 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2010, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	634,505	$ 24.24
Granted	229,988	17.40
Vested	(175,596)	23.55
Forfeited	(19,212)	20.05
Nonvested at end of period	669,685	$ 22.19

Note 14 – Income Taxes

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

	2010	2009	2008
		(In thousands)	
United States	$ 336,450	$ (227,021)	$ 436,029
Foreign	30,100	7,655	5,120
Income (loss) before income taxes	$ 366,550	$ (219,366)	$ 441,149

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

	2010	2009	2008
		(In thousands)	
Current:			
Federal	$ 37,014	$ 64,389	$ 82,279
State	10,589	8,284	(184)
Foreign	4,451	254	(104)
	52,054	72,927	81,991
Deferred:			
Income taxes –			
Federal	62,618	(147,607)	59,963
State	4,147	(22,370)	5,332
Investment tax credit – net	(180)	213	(405)
	66,585	(169,764)	64,890
Change in uncertain tax benefits	3,230	562	422
Change in accrued interest	661	183	173
Total income tax expense (benefit)	$ 122,530	$ (96,092)	$ 147,476

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

	2010	2009
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$ 114,427	$ 85,712
Accrued pension costs	82,085	79,052
Asset retirement obligations	24,391	24,091
Compensation-related	17,261	18,773
Other	53,929	42,492
Total deferred tax assets	292,093	250,120
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	679,809	601,426
Basis differences on natural gas and oil producing properties	152,455	116,521
Regulatory matters	64,017	53,835
Intangible asset amortization	14,843	12,975
Other	20,348	28,186
Total deferred tax liabilities	931,472	812,943
Net deferred income tax liability	$ (639,379)	$ (562,823)

As of December 31, 2010 and 2009, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2009, to December 31, 2010, to deferred income tax expense:

	2010
	(In thousands)
Change in net deferred income tax liability from the preceding table	$ 76,556
Deferred taxes associated with other comprehensive loss	6,657
Other	(16,628)
Deferred income tax expense for the period	$ 66,585

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

Years ended December 31,	2010		2009		2008	
	Amount	%	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	$128,293	35.0	$(76,778)	35.0	$154,402	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	10,210	2.8	(7,280)	3.3	10,709	2.4
Depletion allowance	(2,810)	(.8)	(2,320)	1.0	(2,932)	(.7)
Deductible K-Plan dividends	(2,309)	(.6)	(2,369)	1.1	(2,144)	(.5)
Federal renewable energy credit	(2,185)	(.6)	(1,452)	.7	(1,235)	(.3)
Foreign operations	(588)	(.2)	(1,148)	.5	423	.1
Domestic production activities deduction	—	—	(856)	.4	(3,031)	(.7)
Resolution of tax matters and uncertain tax positions	667	.2	881	(.4)	595	.1
Other	(8,748)	(2.4)	(4,770)	2.2	(9,311)	(2.0)
Total income tax expense (benefit)	$122,530	33.4	$(96,092)	43.8	$147,476	33.4

The income tax benefit in 2009 resulted largely from the Company's write-down of natural gas and oil properties, as discussed in Note 1.

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $11.5 million at December 31, 2010. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2010, was approximately $3.2 million.

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal, state and local, or non-U.S. income tax examinations by tax authorities for years ending prior to 2007.

A reconciliation of the unrecognized tax benefits (excluding interest) for the years ended December 31, was as follows:

	2010	2009	2008
		(In thousands)	
Balance at beginning of year	$ 6,148	$ 5,586	$ 3,735
Additions based on tax positions related to the current year	—	—	1,102
Additions for tax positions of prior years	3,230	562	1,811
Reductions for tax positions of prior years	—	—	(1,062)
Balance at end of year	$ 9,378	$ 6,148	$ 5,586

Included in the balance of unrecognized tax benefits at December 31, 2010, were $3.8 million of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate at December 31, 2010, was $7.1 million, including approximately $1.5 million for the payment of interest and penalties.

The Company does not anticipate the amount of unrecognized tax benefits to significantly increase or decrease within the next 12 months.

For the years ended December 31, 2010, 2009 and 2008, the Company recognized approximately $2.0 million, $190,000 and $819,000, respectively, in interest expense. Penalties were not material in 2010, 2009 and 2008. The Company recognized interest income of approximately $20,000, $165,000 and $223,000 for the years ended December 31, 2010, 2009 and 2008, respectively. The Company had accrued liabilities of approximately $2.3 million, $1.6 million and $1.4 million at December 31, 2010, 2009 and 2008, respectively, for the payment of interest.

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 Centennial Resources' equity method investment in the Brazilian Transmission Lines.

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 Idaho, Minnesota, Oregon and Washington. These operations also supply related value-added products and services.

The construction services segment specializes in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization equipment. This segment also provides utility excavation services and inside electrical wiring, cabling and mechanical services, sells and distributes electrical materials, and manufactures and distributes 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. This segment also provides cathodic protection and energy-related services.

The natural gas and oil production segment is engaged in natural gas and oil acquisition, exploration, development and production activities in the Rocky Mountain and Mid-Continent regions of the United States and in and around the Gulf of Mexico.

The construction materials and contracting 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 contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

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 Other category also includes Centennial Resources' equity method investment in the Brazilian Transmission Lines.

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:

	2010	2009	2008
		(In thousands)	
External operating revenues:			
Electric	$211,544	$196,171	$208,326
Natural gas distribution	892,708	1,072,776	1,036,109
Pipeline and energy services	254,776	235,322	440,764
	1,359,028	1,504,269	1,685,199
Construction services	786,802	818,685	1,256,759
Natural gas and oil production	318,570	338,425	420,637
Construction materials and contracting	1,445,148	1,515,122	1,640,683
Other	147	—	—
	2,550,667	2,672,232	3,318,079
Total external operating revenues	$3,909,695	$4,176,501	$5,003,278
Intersegment operating revenues:			
Electric	$—	$—	$—
Natural gas distribution	—	—	—
Construction services	2,298	379	560
Pipeline and energy services	75,033	72,505	91,389
Natural gas and oil production	115,784	101,230	291,642
Construction materials and contracting	—	—	—
Other	7,580	9,487	10,501
Intersegment eliminations	(200,695)	(183,601)	(394,092)
Total intersegment operating revenues	$—	$—	$—

Depreciation, depletion and amortization:			
Electric	$27,274	$24,637	$24,030
Natural gas distribution	43,044	42,723	32,566
Construction services	12,147	12,760	13,398
Pipeline and energy services	26,001	25,581	23,654
Natural gas and oil production	130,455	129,922	170,236
Construction materials and contracting	88,331	93,615	100,853
Other	1,591	1,304	1,283
Total depreciation, depletion and amortization	$328,843	$330,542	$366,020
Interest expense:			
Electric	$12,216	$9,577	$8,674
Natural gas distribution	28,996	30,656	24,004
Construction services	4,411	4,490	4,893
Pipeline and energy services	9,064	8,896	8,314
Natural gas and oil production	8,580	10,621	12,428
Construction materials and contracting	19,859	20,495	24,291
Other	47	43	374
Intersegment eliminations	(162)	(679)	(1,451)
Total interest expense	$83,011	$84,099	$81,527
Income taxes:			
Electric	$11,187	$8,205	$8,225
Natural gas distribution	12,171	16,331	18,827
Construction services	11,456	15,189	26,952
Pipeline and energy services	13,933	22,982	15,427
Natural gas and oil production	49,034	(187,000)	68,701
Construction materials and contracting	13,822	25,940	8,947
Other	10,927	2,261	397
Total income taxes	$122,530	$(96,092)	$147,476
Earnings (loss) on common stock:			
Electric	$28,908	$24,099	$18,755
Natural gas distribution	36,944	30,796	34,774
Construction services	17,982	25,589	49,782
Pipeline and energy services	23,208	37,845	26,367
Natural gas and oil production	85,638	(296,730)	122,326
Construction materials and contracting	29,609	47,085	30,172
Other	21,046	7,357	10,812
Earnings (loss) on common stock before loss from discontinued operations	243,335	(123,959)	292,988
Loss from discontinued operations, net of tax	(3,361)	—	—
Total earnings (loss) on common stock	$239,974	$(123,959)	$292,988

Capital expenditures:			
Electric	$85,787	$115,240	$72,989
Natural gas distribution	75,365	43,820	398,116
Construction services	14,849	12,814	24,506
Pipeline and energy services	14,255	70,168	42,960
Natural gas and oil production	355,845	183,140	710,742
Construction materials and contracting	25,724	26,313	127,578
Other	2,182	3,196	774
Net proceeds from sale or disposition of property and other	(78,761)	(26,679)	(86,927)
Total net capital expenditures	$495,246	$428,012	$1,290,738
Assets:			
Electric*	$643,636	$569,666	$479,639
Natural gas distribution*	1,632,012	1,588,144	1,548,005
Construction services	387,627	328,895	476,092
Pipeline and energy services	523,075	538,230	506,872
Natural gas and oil production	1,342,808	1,137,628	1,792,792
Construction materials and contracting	1,382,836	1,449,469	1,552,296
Other**	391,555	378,920	232,149
Total assets	$6,303,549	$5,990,952	$6,587,845
Property, plant and equipment:			
Electric*	$1,027,034	$941,791	$848,725
Natural gas distribution*	1,508,845	1,456,208	1,429,487
Construction services	122,940	116,236	111,301
Pipeline and energy services	683,807	675,199	640,921
Natural gas and oil production	2,356,938	2,028,794	2,477,402
Construction materials and contracting	1,486,375	1,514,989	1,524,029
Other	32,564	33,365	30,372
Less accumulated depreciation, depletion and amortization	3,103,323	2,872,465	2,761,319
Net property, plant and equipment	$4,115,180	$3,894,117	$4,300,918

* 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).

Note: The results reflect a $620.0 million ($384.4 million after tax) and $135.8 million ($84.2 million after tax) noncash write-down of natural gas and oil properties in 2009 and 2008, respectively.

Excluding the natural gas gathering arbitration charge of $16.5 million (after tax) in 2010, as discussed in Note 19, earnings from electric, natural gas distribution and pipeline and energy services are substantially all from regulated operations. Earnings from construction services, natural gas and oil production, construction materials and contracting, and other are all from nonregulated operations.

Capital expenditures for 2010, 2009 and 2008 include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions and the outstanding indebtedness related to the 2008 Intermountain acquisition. The net noncash transactions were $17.5 million in 2010; immaterial in 2009 and $97.6 million in 2008.

Note 16 – Employee Benefit Plans
The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. The Company uses a measurement date of December 31 for all of its pension and postretirement benefit plans.

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

Effective January 1, 2010, eligibility to receive retiree medical benefits was modified at certain of the Company's businesses. Current employees who attain age 55 with 10 years of continuous service by December 31, 2010, will be provided the current retiree medical insurance benefits or can elect the new benefit, if desired, regardless of when they retire. All other current employees must meet the new eligibility criteria of age 60 and 10 years of continuous service at the time they retire. These employees will be eligible for a specified company funded Retiree Reimbursement Account. Employees hired after December 31, 2009, will not be eligible for retiree medical benefits.

Changes in benefit obligation and plan assets for the years ended December 31, 2010 and 2009, and amounts recognized in the Consolidated Balance Sheets at December 31, 2010 and 2009, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$352,915	$358,525	$88,151	$94,325
Service cost	2,889	8,127	1,357	2,206
Interest cost	19,761	21,919	4,817	5,465
Plan participants' contributions	—	—	2,500	2,369
Amendments	353	—	121	(9,319)
Actuarial loss	34,687	26,188	3,228	813
Curtailment gain	—	(38,166)	—	—
Benefits paid	(22,016)	(23,678)	(8,888)	(7,708)
Benefit obligation at end of year	388,589	352,915	91,286	88,151
Change in net plan assets:				
Fair value of plan assets at beginning of year	255,327	226,214	66,984	60,085
Actual gain on plan assets	37,853	42,084	7,278	8,600
Employer contribution	6,434	10,707	2,736	3,638
Plan participants' contributions	—	—	2,500	2,369
Benefits paid	(22,016)	(23,678)	(8,888)	(7,708)
Fair value of net plan assets at end of year	277,598	255,327	70,610	66,984
Funded status – under	$(110,991)	$(97,588)	$(20,676)	$(21,167)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	$—	$—	$(525)	$(459)
Other liabilities (noncurrent)	(110,991)	(97,588)	(20,151)	(20,708)
Net amount recognized	$(110,991)	$(97,588)	$(20,676)	$(21,167)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	$117,840	$99,985	$20,751	$20,134
Prior service cost (credit)	631	430	(11,292)	(14,716)
Transition obligation	—	—	4,253	6,378
Total	$118,471	$100,415	$13,712	$11,796

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time.

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized on a straight-line basis over the expected average remaining service lives of active participants for non-frozen plans and over the average life expectancy of plan participants for frozen plans. 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 previously was $374.5 million and $340.3 million at December 31, 2010 and 2009, 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 were as follows:

	2010	2009
	(In thousands)	
Projected benefit obligation	$ 388,589	$ 352,915
Accumulated benefit obligation	$ 374,538	$ 340,341
Fair value of plan assets	$ 277,598	$ 255,327

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

	Pension Benefits			Other Postretirement Benefits		
	2010	2009	2008	2010	2009	2008
			(In thousands)			
Components of net periodic benefit cost:						
Service cost	$2,889	$8,127	$8,812	$1,357	$2,206	$1,977
Interest cost	19,761	21,919	21,264	4,817	5,465	5,079
Expected return on assets	(23,643)	(25,062)	(26,501)	(5,512)	(5,471)	(5,657)
Amortization of prior service cost (credit)	152	605	665	(3,303)	(2,756)	(2,755)
Recognized net actuarial loss	2,622	2,096	1,050	845	970	594
Curtailment loss	—	1,650	—	—	—	—
Amortization of net transition obligation	—	—	—	2,125	2,125	2,125
Net periodic benefit cost, including amount capitalized	1,781	9,335	5,290	329	2,539	1,363
Less amount capitalized	791	1,127	642	(92)	330	307
Net periodic benefit cost	990	8,208	4,648	421	2,209	1,056
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	20,477	(29,000)	102,125	1,462	(2,314)	26,478
Prior service cost (credit)	353	—	—	121	(9,321)	(382)
Amortization of actuarial loss	(2,622)	(2,096)	(1,050)	(845)	(970)	(594)
Amortization of prior service (cost) credit	(152)	(2,255)	(665)	3,303	2,756	2,755
Amortization of net transition obligation	—	—	—	(2,125)	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	18,056	(33,351)	100,410	1,916	(11,974)	26,132
Total recognized in net periodic benefit cost and accumulated other comprehensive (income)	$19,046	$(25,143)	$105,058	$2,337	$(9,765)	$27,188

loss

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 2011 are $4.9 million and $173,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2011 are $838,000, $2.7 million and $2.1 million, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
Discount rate	5.26 %	5.75 %	5.21 %	5.75 %
Expected return on plan assets	7.75 %	8.25 %	6.75 %	7.25 %
Rate of compensation increase	4.00 %	4.00 %	4.00 %	4.00 %

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

	Pension Benefits		Other Postretirement Benefits	
	2010	2009	2010	2009
Discount rate	5.75 %	6.25 %	5.75 %	6.25 %
Expected return on plan assets	8.25 %	8.50 %	7.25 %	7.50 %
Rate of compensation increase	4.00 %	4.00 %	4.00 %	4.00 %

The expected rate of return on pension plan assets is based on the targeted asset allocation range of 60 percent to 70 percent equity securities and 30 percent to 40 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 65 percent to 75 percent equity securities and 25 percent to 35 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:

	2010	2009
Health care trend rate assumed for next year	6.0%-8.5 %	6.0%-9.0 %
Health care cost trend rate – ultimate	5.0%-6.0 %	5.0%-6.0 %
Year in which ultimate trend rate achieved	1999-2017	1999-2017

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, 2010:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 106	$ (751)
Effect on postretirement benefit obligation	$ 2,593	$ (10,086)

The Company's pension assets are managed by 12 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 futures 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 fair value of the Company's pension net plan assets by class is as follows:

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Cash and cash equivalents	$4,663	$8,699	$ —	$ 13,362
Equity securities:				
U.S. companies	102,944	—	—	102,944
International companies	40,017	—	—	40,017
Collective and mutual funds (a)	45,410	17,701	—	63,111
Collateral held on loaned securities (b)	—	23,148	694	23,842
Corporate bonds	—	23,014	—	23,014
Mortgage-backed securities	—	19,478	—	19,478
U.S. Treasury securities	—	9,239	—	9,239
Municipal bonds	—	8,285	—	8,285
Total assets measured at fair value	193,034	109,564	694	303,292
Liabilities:				
Obligation for collateral received	25,694	—	—	25,694
Net assets measured at fair value	$167,340	$109,564	$ 694	$ 277,598

(a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed-income investments and 6 percent in common stock of small-cap U.S. companies.

(b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

	Fair Value Measurements at December 31, 2009, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2009
	(In thousands)			
Assets:				
Common stocks (a)	$133,989	$—	$ —	$ 133,989
Collective and mutual funds (b)	39,234	10,379	—	49,613
U.S. government and U.S. government-sponsored securities (c)	—	28,091	—	28,091
Corporate and municipal bonds (d)	—	27,968	—	27,968
Collateral held on loaned securities (e)	—	21,597	937	22,534
Cash and cash equivalents	17,958	—	—	17,958
Total assets measured at fair value	191,181	88,035	937	280,153
Liabilities:				
Obligation for collateral received	24,826	—	—	24,826
Net assets measured at fair value	$166,355	$88,035	$ 937	$ 255,327

(a) This category includes approximately 75 percent U.S. common stocks and 25 percent non-U.S. common stocks.
(b) Collective and mutual funds invest approximately 43 percent in common stock of large-cap U.S. companies, 21 percent in asset-backed securities, 17 percent in cash and cash equivalents, 8 percent in small-cap U.S. companies and 11 percent in other investments.
(c) This category includes approximately 69 percent U.S. government-sponsored securities (asset-backed securities) and 31 percent U.S. government securities.
(d) This category includes approximately 78 percent corporate bonds and 22 percent municipal bonds.
(e) This category includes collateral held at December 31, 2009, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, money market funds, corporate bonds, commercial paper, asset-backed securities and certificates of deposit.

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2010:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Collateral Held on Loaned Securities (In thousands)
Balance at beginning of year	$ 937
Total realized/unrealized losses	189
Purchases, issuances and settlements (net)	(432)
Balance at end of year	$ 694

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2009:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3) Collateral Held on Loaned Securities (In thousands)
Balance at beginning of year	$ 573
Total realized/unrealized losses	80
Purchases, issuances and settlements (net)	284
Balance at end of year	$ 937

The fair value of the Company's other postretirement benefit plan assets by asset class is as follows:

	Fair Value Measurements at December 31, 2010, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
	(In thousands)			
Assets:				
Cash and cash equivalents	$53	$1,274	$ —	$ 1,327
Equity securities:				
U.S. companies	2,791	—	—	2,791
International companies	353	—	—	353
Insurance investment contract*	—	66,139	—	66,139
Total assets measured at fair value	$3,197	$67,413	$ —	$ 70,610

* The insurance investment contract invests approximately 53 percent in common stock of large-cap U.S. companies, 21 percent in corporate bonds, 12 percent in mortgage-backed securities and 14 percent in other investments.

The fair value of the Company's other postretirement benefit plan assets by asset category is as follows:

	Fair Value Measurements at December 31, 2009, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2009
	(In thousands)			
Assets:				
Money market funds	$1,469	$—	$ —	$ 1,469
Common stock	2,897	—	—	2,897
Insurance investment contract*	—	62,618	—	62,618
Total assets measured at fair value	$4,366	$62,618	$ —	$ 66,984

* Invested in mutual funds.

The Company expects to contribute approximately $34.2 million to its defined benefit pension plans and approximately $2.9 million to its postretirement benefit plans in 2011.

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

Years	Pension Benefits	Other Postretirement Benefits
	(In thousands)	
2011	$ 21,616	$ 6,322
2012	22,078	6,433
2013	22,556	6,622
2014	22,930	6,772
2015	23,438	6,891
2016 - 2020	126,190	35,583

The following Medicare Part D subsidies are expected: $698,000 in 2011; $748,000 in 2012; $790,000 in 2013; $829,000 in 2014; $871,000 in 2015; and $4.9 million during the years 2016 through 2020.

In addition to company-sponsored plans, certain employees are covered under multi-employer pension plans administered by third parties unaffiliated with the Company. Amounts contributed in 2010 to defined benefit and defined contribution multi-employer plans were $30.3 million and $15.4 million, respectively. Amounts contributed in 2009 to defined benefit and defined contribution multi-employer plans were $32.5 million and $16.4 million, respectively. Amounts contributed to the multi-employer plans were $73.1 million in 2008.

The information available to the Company about the multi-employer plans in which it participates, whether via request to the plan or publicly available, is generally dated (in many cases more than twelve months old) due to the nature of the reporting cycle of multi-employer plans and legal requirements under ERISA as amended by MPPAA. Based on available information, the Company believes that approximately 35 of the multi-employer pension plans to which it contributes were classified under the Pension Protection Act of 2006 as being in either endangered, seriously endangered or critical status. These plans have or were adopting a funding improvement or rehabilitation plan that may require increased contributions, reduced benefits or a combination of the two. Based on information available to the Company about funding improvement or rehabilitation plans adopted by the multi-employer plans to which it contributes, the Company does not expect the potential increased contributions to have a material negative impact on its financial condition, results of operations and cash flows for 2011. However, the Company could incur a material increase in contributions and/or obligations, as additional details about the funding status of the plans becomes available to the Company.

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $77.5 million and $67.9 million at December 31, 2010 and 2009, respectively, consisting of equity securities of $39.5 million and $32.1 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $30.7 million and $29.8 million, respectively, and other investments of $7.3 million and $3.3 million, respectively. The Company also had investments in fixed-income securities of $2.7 million at December 31, 2009. The Company anticipates using these investments to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $7.8 million, $8.8 million and $9.0 million in 2010, 2009 and 2008, respectively. The total projected benefit obligation for these plans was $99.4 million and $93.0 million at December 31, 2010 and 2009, respectively. The accumulated benefit obligation for these plans was $93.2 million and $84.8 million at December 31, 2010 and 2009, respectively. A weighted average discount rate of 5.11 percent and 5.75 percent at December 31, 2010 and 2009, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2010 and 2009, were used to determine benefit obligations. A discount rate of 5.75 percent and 6.25 percent at December 31, 2010 and 2009, respectively, and a rate of compensation increase of 4.00 percent at December 31, 2010 and 2009, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.0 million in 2011; $5.3 million in 2012; $5.9 million in 2013; $5.8 million in 2014; $6.9 million in 2015; and $37.0 million for the years 2016 through 2020.

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $24.4 million in 2010, $20.5 million in 2009 and $23.8 million in 2008.

Note 17 – Jointly Owned Facilities

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

The Company's share of the Big Stone Station, Coyote Station and Wygen III 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:

	2010	2009
	(In thousands)	
Big Stone Station:		
Utility plant in service	$ 60,404	$ 60,220
Less accumulated depreciation	41,136	39,940
	$ 19,268	$ 20,280
Coyote Station:		
Utility plant in service	$ 131,395	$ 131,042
Less accumulated depreciation	84,710	82,402
	$ 46,685	$ 48,640
Wygen III:*		
Utility plant in service	$ 63,215	$ —
Less accumulated depreciation	838	—
	$ 62,377	$ —

* Began commercial operation on April 1, 2010.

Note 18 – Regulatory Matters and Revenues Subject to Refund

On April 19, 2010, Montana-Dakota filed an application with the NDPSC for an electric rate increase. Montana-Dakota requested a total increase of $15.4 million annually or approximately 14 percent above current rates. The requested increase included the investment in infrastructure

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upgrades, recovery of the investment in renewable generation, the costs associated with Big Stone Station II and the significant loss of wholesale sales margins. On June 16, 2010, the NDPSC approved an interim increase of $7.6 million effective with service rendered June 18, 2010. On June 16, 2010, Montana-Dakota and the NDPSC Advocacy Staff filed a partial settlement agreement agreeing to an overall rate of return and a sharing of earnings over a specified return on equity. On July 6, 2010, Montana-Dakota filed an amendment to its application to exclude the development costs associated with Big Stone Station II because of a settlement agreement approved by the NDPSC that provided for recovery of such development costs. On November 8, 2010, Montana-Dakota and the NDPSC Advocacy Staff filed a second settlement agreement resolving certain issues raised by the NDPSC Advocacy Staff in its investigation of the rate increase application. Montana-Dakota revised its requested rate increase to $8.8 million annually or 7.7 percent as a result of the settlements, the exclusion of the Big Stone Station II development costs and other adjustments. The NDPSC Advocacy Staff sought reductions of $8.3 million annually from Montana-Dakota's requested increase. A hearing on the application was held the week of November 8, 2010, and an order is anticipated in the first quarter of 2011. In the event of an adverse order, some or all of the revenues collected by Montana-Dakota from the interim rate increase may be subject to refund.

On August 12, 2010, Montana-Dakota filed an application with the MTPSC for an electric rate increase. Montana-Dakota requested a total increase of $5.5 million annually or approximately 13 percent above current rates. The requested increase included the investment in infrastructure upgrades, recovery of the investment in renewable generation, the costs associated with Big Stone Station II and the significant loss of wholesale sales margins. A hearing on the application has been set for February 28, 2011. Montana-Dakota requested an interim increase of $3.1 million or approximately 7.4 percent. On February 8, 2011, the MTPSC approved an interim increase of $2.6 million or approximately 6.28 percent, effective with service rendered February 14, 2011.

Note 19 – Commitments and Contingencies

The Company has reserved $45.3 million for potential liabilities related to litigation and environmental matters, which includes $26.6 million related to the natural gas gathering operations as well as amounts that may be reserved for other matters discussed in litigation and environmental matters within this note.

Litigation

Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent Power LLC, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation, which letter of credit expired November 1, 2010. In February 2009, Centennial received a Notice and Demand from LPP under the guaranty agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand seeks compensatory damages of $146 million plus damages for increased operating, capital and construction costs related to a water treatment facility for the generating facility. LPP's notice of demand for arbitration also demanded performance of the guarantee by Centennial. In June 2010, CEM and Bicent Power LLC made a demand on Centennial Resources for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs which CEM and Bicent

Power LLC allege are more than $5.0 million, arising from LPP's arbitration demand and related to Centennial Resources' ownership of CEM prior to its sale from Centennial Resources to Bicent Power LLC. The Company believes the claims against Centennial and Centennial Resources are without merit and intends to vigorously defend against such claims. Centennial and Centennial Resources filed a complaint with the Supreme Court of the State of New York on November 4, 2010, against CEM and Bicent Power LLC seeking damages for breach of contract and other relief including specific performance of the 2007 purchase and sale agreement allowing for Centennial Resources' participation in the arbitration proceeding and replacement of the letter of credit. The arbitration hearing on LPP's claim is currently scheduled for late in the third quarter of 2011. On January 28, 2011, CEM and Bicent Power LLC filed a motion to dismiss the complaint filed by Centennial and Centennial Resources.

Construction Materials LTM is a defendant in litigation pending in Oregon Circuit Court regarding the concrete floors in an industrial food processing facility in Jackson County, Oregon. The plaintiffs assert claims against LTM, which supplied the concrete for the floors, and others that the concrete floors of the facility are defective and must be removed and replaced for suitable repair. Damages, including disruption of the food processing operations, have been estimated by the plaintiffs to be approximately $26.5 million. A settlement agreement has been reached on the claims against LTM for an amount that was recorded as a liability and was not material to the Company's financial position, results of operations, or cash flows.

In 2009, LTM provided pavement work under a subcontract for reconstruction at the Klamath Falls Airport owned by the City of Klamath Falls, Oregon. On October 15, 2010, the City of Klamath Falls filed a complaint against the project's general contractor alleging the work performed by LTM is defective. The general contractor tendered the defense and indemnity of the claim to LTM and its insurance carrier. LTM's insurance carrier accepted defense of the claim. On January 18, 2011, the general contractor served a third party complaint against LTM seeking indemnity and contribution for damages imposed on the general contractor. Damages, including removal and replacement of the paved runway, are estimated by the plaintiff as $6.0 million to $11.0 million. LTM believes its work met the specifications of the subcontract and expects to vigorously defend against the claims.

Natural Gas Gathering Operations On January 11, 2010, SourceGas filed an application with the Colorado State District Court to compel Bitter Creek to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of Bitter Creek's pipeline gathering systems in Montana. Bitter Creek resisted the application and sought a declaratory order interpreting the gathering contract. On May 28, 2010, the Colorado State District Court granted the application and ordered Bitter Creek into arbitration. An arbitration hearing was held August 23-31, 2010. On October 15, 2010, Bitter Creek was notified that the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, Bitter Creek, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010, which is recorded in operation and maintenance expense on the Consolidated Statement of Income. On November 3, 2010, SourceGas filed a motion with the Colorado State District Court to confirm the arbitration award and enter judgment. Bitter Creek filed a motion on November 15, 2010, with the Colorado State District Court to vacate the arbitration award.

In related matters, Noble Energy, Inc. made a written demand on December 10, 2010, to Bitter Creek and SourceGas for arbitration under the gathering contract between Bitter Creek and SourceGas. Noble Energy, Inc. contends it is a third party beneficiary of the contract and alleges it is damaged by the increased operating pressures demanded by SourceGas on the natural gas gathering system. Bitter Creek filed a complaint in Colorado State District Court to enjoin arbitration by Noble Energy, Inc. On July 30, 2010, Omimex Canada, Ltd. filed a complaint against Bitter Creek in Montana District Court alleging Bitter Creek breached a separate gathering contract with Omimex Canada, Ltd. as a result of the increased operating pressures on the same natural gas gathering system. Omimex Canada, Ltd. seeks unspecified damages and injunctive relief.

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, results of operations or cash flows.

Environmental matters
Portland Harbor Site In December 2000, MBI was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by MBI from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. 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 and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include MBI or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. MBI also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are 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 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 limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against MBI and others to recover LWG's investigation costs to the extent MBI cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, MBI has agreed to participate in the alternative dispute resolution process.

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

Manufactured Gas Plant Sites There are three claims against Cascade for cleanup of environmental contamination at manufactured gas plant sites operated by Cascade's predecessors.

The first claim is for soil and groundwater contamination at a site in Oregon and was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination.

Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. An ecological risk assessment draft report was submitted to the Oregon DEQ in June 2009. The assessment showed no unacceptable risk to the aquatic ecological receptors present in the shoreline along the site and concluded that no further ecological investigation is necessary. The report is being reviewed by the Oregon DEQ. It is anticipated the Oregon DEQ will recommend a cleanup alternative for the site after it completes its review of the report. It is not known at this time what share of the cleanup costs will actually be borne by Cascade.

The second claim is for contamination at a site in Washington and was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. Cascade received notice in April 2010, that the Washington Department of Ecology has determined that Cascade is a PRP for release of hazardous substances at the site. On October 18, 2010, Cascade received notice from the United States Coast Guard that a hazardous substance appearing to be manufactured gas plant waste was released into the waterway from an abandoned pipe located on the shoreline in the vicinity of the former manufactured gas plant. Cascade subsequently received an administrative order from the United States Coast Guard requiring Cascade to remove the abandoned pipe and conduct other associated time-critical actions. Cascade agreed to remove the pipe and perform the other time-critical actions pursuant to a work plan approved by the United States Coast Guard. The work satisfying the administrative order was completed in November 2010. It is expected that subsequent remedial action at the site will be conducted under the oversight of the EPA. Cascade has reserved $6.4 million for remediation of this site. On April 9, 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition on September 16, 2010, subject to conditions set forth in the order.

The third claim is also for contamination at a site in Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. The remediation investigation and feasibility study report are expected to be completed by late 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim.

To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

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, 2010, were $25.4 million in 2011, $20.3 million in 2012, $17.3 million in 2013, $9.4 million in 2014, $4.3 million in 2015 and $50.3 million thereafter. Rent expense was $38.7 million, $43.4 million and $35.3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Purchase commitments
The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage and construction materials supply contracts. These commitments range from one to 50 years. The commitments under these contracts as of December 31, 2010, were $497.9 million in 2011, $296.5 million in 2012, $206.5 million in 2013, $110.0 million in 2014, $49.9 million in 2015 and $195.3 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2010, 2009 and 2008, were $611.7 million, $723.1 million, and approximately $1.0 billion (including the acquisition of Intermountain as discussed in Note 2), respectively.

Guarantees
Centennial guaranteed CEM's obligations under a construction contract. For further information, see litigation in this note.

In connection with the sale of the Brazilian Transmission Lines, as discussed in Note 4, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

WBI Holdings has guaranteed certain of Fidelity's natural gas and oil swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil 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 swap and collar agreements at December 31, 2010, expire in 2011 and 2012; 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. The amount outstanding by Fidelity was $15.6 million and was reflected on the Consolidated Balance Sheet at December 31, 2010. 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 construction contracts, natural gas transportation and sales agreements, gathering contracts, a conditional purchase agreement and certain other guarantees. At December 31, 2010, the fixed maximum amounts guaranteed under these agreements aggregated $208.5 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $142.3 million in 2011; $56.0 million in 2012; $1.4 million in 2013; $200,000 in 2014; $900,000 in 2018; $300,000 in 2019; $3.4 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $1.4 million and was reflected on the Consolidated Balance Sheet at December 31,

2010. 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.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, materials obligations, natural gas transportation agreements and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2010, the fixed maximum amounts guaranteed under these letters of credit, aggregated $28.8 million. In 2011 and 2012, $24.6 million and $4.2 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at December 31, 2010.

WBI Holdings has an outstanding guarantee to Williston Basin. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2010, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2011. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.4 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2010, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the Company's routine purchase of maintenance items, materials 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 these guarantee obligations, Centennial, Knife River or MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2010.

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, 2010, approximately $448 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Supplementary Financial Information
Quarterly Data (Unaudited)
The following unaudited information shows selected items by quarter for the years 2010 and 2009:

	First Quarter*	Second Quarter	Third Quarter**	Fourth Quarter ***
	(In thousands, except per share amounts)			
2010				
Operating revenues	$834,777	$906,444	$1,125,923	$1,042,551
Operating expenses	751,848	817,782	1,016,961	912,377
Operating income	82,929	88,662	108,962	130,174
Income from continuing operations	41,772	48,938	61,010	92,300
Loss from discontinued operations, net of tax	—	—	—	(3,361)
Net income	41,772	48,938	61,010	88,939
Earnings per common share – basic:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share – basic	.22	.26	.32	.47
Earnings per common share – diluted:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share – diluted	.22	.26	.32	.47
Weighted average common shares outstanding:				
Basic	187,963	188,129	188,170	188,281
Diluted	188,220	188,267	188,338	188,374
2009				
Operating revenues	$1,094,005	$958,040	$1,107,927	$1,016,529
Operating expenses	1,634,924	857,975	947,654	889,045
Operating income (loss)	(540,919)	100,065	160,273	127,484
Net income (loss)	(343,803)	55,311	92,584	72,634
Earnings (loss) per common share:				
Basic	(1.87)	.30	.50	.39
Diluted	(1.87)	.30	.50	.38
Weighted average common shares outstanding:				
Basic	183,787	183,964	185,160	187,748
Diluted	183,787	184,398	185,425	188,373

* 2009 reflects a $384.4 million after-tax noncash write-down of natural gas and oil properties. For more information, see Note 1.

** 2010 reflects a natural gas gathering arbitration charge of $16.5 million (after tax). For more information, see Note 19.

*** 2010 reflects a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines. For more information, see Note 4.

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 and oil production properties. Fidelity shares revenues and expenses from the development of specified properties in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States in proportion to its ownership interests.

Fidelity owns in fee or holds natural gas and oil leases for the properties it operates in Colorado, Montana, North Dakota, Texas, Utah and Wyoming. These rights are in the Bonny Field in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area in north-central Montana, the Powder River Basin of Montana and Wyoming, the Bakken area in North Dakota, the Paradox Basin of Utah, the Tabasco and Texan Gardens fields of Texas, Rusk County in eastern Texas and the Big Horn Basin in Wyoming. In 2010, Fidelity acquired natural gas properties in the Green River Basin in Wyoming and also acquired undeveloped acreage in the emerging Niobrara play in Wyoming and expanded its acreage position in the Bakken play.

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:

	2010	2009	2008
		(In thousands)	
Subject to amortization	$ 2,138,565	$ 1,815,380	$ 2,211,865
Not subject to amortization	182,402	178,214	232,081
Total capitalized costs	2,320,967	1,993,594	2,443,946
Less accumulated depreciation, depletion and amortization	1,093,723	969,630	846,074
Net capitalized costs	$ 1,227,244	$ 1,023,964	$ 1,597,872

Note: Net capitalized costs reflect noncash write-downs of the Company's natural gas and oil properties, as discussed in Note 1.

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

Years ended December 31,	2010 *	2009 *	2008 *
		(In thousands)	
Acquisitions:			
Proved properties	$ 89,733	$ 3,879	$ 225,610
Unproved properties	92,100	8,771	107,419
Exploration	33,226	33,123	109,828
Development	139,733	135,202	260,098
Total capital expenditures	$ 354,792	$ 180,975	$ 702,955

*Excludes net additions to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of natural gas and oil wells, as discussed in Note 10, of $11.1 million, $2.0 million and $3.0 million for the years ended December 31, 2010, 2009 and 2008, 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,	2010	2009	2008
		(In thousands)	
Revenues:			
Sales to affiliates	$ 115,784	$ 101,230	$ 291,642
Sales to external customers	318,565	338,425	420,488
Production costs	127,403	123,148	161,401
Depreciation, depletion and amortization*	127,266	126,278	167,427
Write-down of natural gas and oil properties	—	620,000	135,800
Pretax income	179,680	(429,771)	247,502
Income tax expense	66,293	(164,216)	91,593
Results of operations for producing activities	$ 113,387	$ (265,555)	$ 155,909

* Includes accretion of discount for asset retirement obligations of $3.2 million, $2.7 million and $2.5 million for the years ended December 31, 2010, 2009 and 2008, respectively, as discussed in Note 10.

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The reserve estimates as of December 31, 2010 and 2009, were calculated using SEC Defined Prices and prior to that time, reserve estimates were calculated using spot market prices that existed at the end of the applicable period. Other factors used in the reserve estimates are current estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

The reserve estimates are prepared by internal engineers assigned to an asset team by geographic area. Senior management reviews and approves the reserve estimates to ensure they are materially accurate. In addition, the Company engaged Ryder Scott, an independent third party, to audit its proved reserve quantity estimates as of December 31, 2010 and 2009.

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.

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 changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2010, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	448,425	34,216	653,724
Production	(50,391)	(3,262)	(69,963)
Extensions and discoveries	36,191	3,389	56,523
Improved recovery	—	—	—
Purchases of proved reserves	55,119	979	60,991
Sales of reserves in place	(92)	(18)	(202)
Revisions of previous estimates	(40,855)	(2,437)	(55,477)
Balance at end of year	448,397	32,867	645,596

Significant changes in proved reserves for the year ended December 31, 2010, include:

- Extensions and discoveries of 56.5 Bcfe primarily due to drilling activity at the Company's Bakken, Baker, Bowdoin and east Texas properties
- Purchases of proved reserves of 61.0 Bcfe as a result of the Company's acquisition of natural gas properties in the Green River Basin in Wyoming, as discussed in Note 2
- Revisions of previous estimates of (55.5) Bcfe largely the result of negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's Bowdoin, south Texas, Baker and east Texas properties and removal of PUD reserves due to the five-year limitation rule, partially offset by positive revisions due to increased natural gas and oil prices

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2009, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	604,282	34,348	810,371
Production	(56,632)	(3,111)	(75,299)
Extensions and discoveries	26,882	2,569	42,297
Improved recovery	—	—	—
Purchases of proved reserves	—	—	—
Sales of reserves in place	(22)	(248)	(1,510)
Revisions of previous estimates	(126,085)	658	(122,135)
Balance at end of year	448,425	34,216	653,724

Significant changes in proved reserves for the year ended December 31, 2009, include:

- Extensions and discoveries of 42.3 Bcfe primarily due to drilling activity at the Company's Bowdoin, Bakken, Baker and east Texas properties
- Revisions of previous estimates of (122.1) Bcfe largely the result of negative revisions resulting from decreased natural gas and oil prices and negative performance revisions resulting primarily from new information gained from production history and developmental drilling activity in the Company's east Texas and south Texas properties

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2008, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	523,737	30,612	707,409
Production	(65,457)	(2,808)	(82,303)
Extensions and discoveries	78,338	4,941	107,985
Improved recovery	—	—	—
Purchases of proved reserves	92,564	834	97,569
Sales of reserves in place	—	—	—
Revisions of previous estimates	(24,900)	769	(20,289)
Balance at end of year	604,282	34,348	810,371

Significant changes in proved reserves for the year ended December 31, 2008, include:

- Extensions and discoveries of 108.0 Bcfe primarily due to drilling activity in the Company's south Texas, Baker, Powder River Basin, Bakken, Bowdoin and Big Horn Basin properties
- Purchases of proved reserves of 97.6 Bcfe primarily as a result of the Company's acquisition of natural gas properties in Rusk County in east Texas, as discussed in Note 2
- Revisions of previous estimates of (20.3) Bcfe largely the result of negative revisions due to decreased natural gas and oil prices

The following table summarizes the breakdown of the Company's proved reserves between proved developed and PUD reserves at December 31:

	2010	2009	2008
Proved developed reserves:			
Natural Gas (MMcf)	334,911	321,561	431,180
Oil (MBbls)	26,586	26,794	26,862
Total (MMcfe)	494,426	482,329	592,353
PUD reserves:			
Natural Gas (MMcf)	113,486	126,864	173,102
Oil (MBbls)	6,281	7,422	7,486
Total (MMcfe)	151,170	171,395	218,018
Total proved reserves:			
Natural Gas (MMcf)	448,397	448,425	604,282
Oil (MBbls)	32,867	34,216	34,348
Total (MMcfe)	645,596	653,724	810,371

As of December 31, 2010, the Company had 151.2 Bcfe of PUD reserves, which is a decrease of 20.2 Bcfe from December 31, 2009. The decrease relates to the Company converting 17.1 Bcfe of its December 31, 2009, PUD reserves into proved developed reserves in 2010, requiring $34.5 million of drilling and completion capital, removal of 15.6 Bcfe of PUD reserves due to the five-year limitation rule, and negative performance revisions applied to PUD locations. These changes were partially offset by new PUD reserves and positive revisions due to increased natural gas and oil prices. The Company did not have any PUD locations that remained undeveloped for five years or more as of December 31, 2010, and all of its PUD locations at December 31, 2010, are expected to be drilled within the next five years. Future development costs estimated to be spent in each of the next three years to develop PUD reserves as of December 31, 2010, are $80.1 million in 2011, $72.7 million in 2012 and $49.6 million in 2013.

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:

	2010	2009	2008
		(In thousands)	
Future cash inflows	$ 3,790,700	$ 2,991,200	$ 3,970,000
Future production costs	1,393,000	1,095,600	1,325,600
Future development costs	312,500	315,000	377,300
Future net cash flows before income taxes	2,085,200	1,580,600	2,267,100
Future income tax expense	432,800	291,000	501,200
Future net cash flows	1,652,400	1,289,600	1,765,900
10% annual discount for estimated timing of cash flows	756,300	630,800	796,100
Discounted future net cash flows relating to proved natural gas and oil reserves	$ 896,100	$ 658,800	$ 969,800

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

	2010	2009	2008
		(In thousands)	
Beginning of year	$ 658,800	$ 969,800	$ 1,361,900
Net revenues from production	(270,000)	(200,900)	(547,000)
Change in net realization	362,400	(364,800)	(687,100)
Extensions and discoveries, net of future production-related costs	130,500	70,500	209,600
Improved recovery, net of future production-related costs	—	—	—
Purchases of proved reserves, net of future production-related costs	99,800	—	138,100
Sales of reserves in place	(500)	(1,100)	—
Changes in estimated future development costs	34,100	43,600	11,000
Development costs incurred during the current year	43,100	46,400	66,300
Accretion of discount	76,500	115,900	183,800
Net change in income taxes	(103,300)	142,800	372,300
Revisions of previous estimates	(132,000)	(155,500)	(132,200)
Other	(3,300)	(7,900)	(6,900)
Net change	237,300	(311,000)	(392,100)
End of year	$ 896,100	$ 658,800	$ 969,800

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

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of natural gas and oil prices over the remaining reserve lives may vary significantly from SEC Defined 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) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in Internal Controls
No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2010, that has materially affected, or is 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

Mine Safety Information
The recently enacted Dodd-Frank Act requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Mine Safety Act. The Dodd-Frank Act requires reporting of the following types of citations or orders:

1. Citations issued under section 104(a) of the Mine Safety Act for violations that could significantly and substantially contribute to the cause and effect of a coal or other mine safety or health hazard.
2. Orders issued under section 104(b) of the Mine Safety Act. Orders are issued under this section when citations issued under section 104(a) have not been totally abated within the time period allowed by the citation or subsequent extensions.
3. Citations or orders issued under section 104(d) of the Mine Safety Act. Citations or orders are issued under this section when it has been determined that the violation is caused by an unwarrantable failure of the mine operator to comply with the standards. An unwarrantable failure occurs when the mine operator is deemed to have engaged in aggravated conduct constituting more than ordinary negligence.
4. Citations issued under Section 110(b)(2) of the Mine Safety Act for flagrant violations. Violations are considered flagrant for repeat or reckless failures to make reasonable efforts to eliminate a known violation of a mandatory health and safety standard that substantially and proximately caused, or reasonably could have been expected to cause, death or serious bodily injury.
5. Imminent danger orders issued under Section 107(a) of the Mine Safety Act. An imminent danger is defined as the existence of any condition or practice in a coal or other mine which could reasonably be expected to cause death or serious physical harm before such condition or practice can be abated.
6. Notice received under Section 104(e) of the Mine Safety Act of a pattern of violations or the potential to have such a pattern of violations that could significantly and substantially contribute to the cause and effect of mine health and safety standards.

The Dodd-Frank Act was enacted in July 2010. During the period since enactment, none of the Company's operating subsidiaries received citations or orders under the following sections of the Mine Safety Act: 104(b), 110(b)(2), 107(a) or 104(e). In addition, the Company did not have any mining-related fatalities during this period. The Company has 127 contests pending before administrative law judges of the Federal Mine Safety and Health Review Commission that involve all types of citations. Of the contests pending, 13 were initiated during the three months ended December 31, 2010, and 19 contests have been initiated since enactment.

Information related to citations and assessments under the Mine Safety Act for the three months ended December 31, 2010, is shown in the following table:

Mine	State	Section 104(a) Citations Issued	Section 104(d) Citations Issued	Citations Contested	Proposed Assessments Levied*
Vernallis Quarry	CA	—	—	—	$ 200
Amyx Pit	ID	1	—	—	562
Little Falls	MN	—	—	2	200
Olson Pit	MN	1	—	3	892
Rittenour Pit	MN	1	—	3	662
Rockville 3 Quarry	MN	1	1	1	—
St Cloud Hwy 10 Site	MN	1	—	—	100
Portable Crusher 3	MT	—	—	—	300
Angell Quarry	OR	1	—	—	525
Azela Quarry	OR	—	—	—	100
Corvallis Fisher Island	OR	—	—	—	207
Quality Rock	OR	3	3	3	—
Springfield Quarry	OR	—	—	—	190
Lampasas Quarry	TX	1	—	—	787
Scarmardo Pit	TX	1	—	—	290
Casper Pit	WY	—	—	—	200
VR Pit	WY	—	—	1	100
Total		11	4	13	$ 5,315

* Proposed assessments listed above could have arisen from citations issued in prior periods. In addition, assessments may not have yet been proposed for citations issued during the period for which the data is reported.

Information related to citations and assessments under the Mine Safety Act since enactment through December 31, 2010, is shown in the following table:

Mine	State	Section 104(a) Citations Issued	Section 104(d) Citations Issued	Citations Contested	Proposed Assessments Levied*	Outstanding as of December 31, 2010
Hallwood Plant	CA	—	—	—	$ —	$ 1,061
KRC Aggregates	CA	2	—	—	—	—
Pebbly Beach Quarry	CA	—	—	—	100	—
Vernallis Quarry	CA	—	—	—	200	—
Halawa Quarry	HI	—	—	—	—	21,675
Kona Sand Plant	HI	—	—	—	—	392
Portable 1	HI	—	—	—	—	100
Puunene Quarry	HI	—	—	—	—	560
Waikapu Quarry	HI	—	—	—	—	100
Becker Portable 2	IA	—	—	3	400	400
Becker Wash Plant 2	IA	1	—	—	462	462
Amyx Pit	ID	1	—	—	562	—
Busse Pit	MN	—	—	—	—	100
Demuth Pit	MN	—	—	—	100	100
Gladen Pit	MN	—	—	—	100	—
Grace Lake West Pit	MN	—	—	—	208	—
Little Falls	MN	—	—	2	200	362
Olson Pit	MN	2	—	3	1,268	592
Rittenour Pit	MN	1	—	3	662	100
Rockville 3 Quarry	MN	1	1	1	—	—
St Cloud Hwy 10 Site	MN	1	—	—	100	—
Vogt Pit	MN	1	—	—	462	462
Billings Wash Plant	MT	—	—	—	100	—
Portable Crusher 3	MT	—	—	—	700	—
Bender Pit	ND	1	—	2	362	100
Dralle Pit	ND	—	—	—	—	300
Pioneer	ND	—	—	—	—	18,500
Wienmann Pit	ND	—	—	—	—	6,400
Advance Aggregate	OR	—	—	—	625	—
Angell Quarry	OR	1	—	—	525	—
Azela Quarry	OR	—	—	—	100	—
Corvallis Fisher Island	OR	—	—	—	207	—
Gresham S & G	OR	—	—	—	1,612	1,512

Kirkland Pit	OR	—	—	—	200	—
Lone Pine Portable	OR	—	—	1	100	100
Quality Rock	OR	3	3	3	—	—
Salem-Reed Pit	OR	—	—	—	243	—
Springfield Quarry	OR	—	—	—	190	—
Lampasas Quarry	TX	1	—	—	787	787
Scarmardo Pit	TX	1	—	—	290	290
Sky High Pit	TX	—	—	—	1,889	—
Colville Pit	WA	—	—	—	100	—
Casper Pit	WY	—	—	—	200	—
VR Pit	WY	—	—	1	100	100
Total		17	4	19	$ 13,154	$ 54,555

* Proposed assessments listed above could have arisen from citations issued in prior periods. In addition, assessments may not have yet been proposed for citations issued during the period for which the data is reported.

The Dodd-Frank Act also requires information to be disclosed about each citation contested before the Federal Mine Safety and Health Review Commission during the time period covered by the periodic report. Please refer to the following table for the required information since enactment of the Dodd-Frank Act through December 31, 2010.

Mine	State	Month Citation Issued	Contest Initiated By	Category of Violation	Proposed Assessments Levied (Dollars)*	Month Citation Closed**	Result of Contest**
Becker Portable 2	IA	7/2010	Operator	104 (a)	$ 100	—	—
Becker Portable 2	IA	7/2010	Operator	104 (a)	100	—	—
Becker Portable 2	IA	7/2010	Operator	104 (a)	100	—	—
Little Falls	MN	10/2010	Operator	104 (a)	100	—	—
Little Falls	MN	11/2010	Operator	104 (a)	100	—	—
Olson Pit	MN	10/2010	Operator	104 (a)	392	—	—
Olson Pit	MN	10/2010	Operator	104 (a)	100	—	—
Olson Pit	MN	10/2010	Operator	104 (a)	100	—	—
Rittenour Pit	MN	10/2010	Operator	104 (a)	100	—	—
Rittenour Pit	MN	10/2010	Operator	104 (a)	100	—	—
Rittenour Pit	MN	10/2010	Operator	104 (a)	362	—	—
Rockville 3 Quarry	MN	11/2010	Operator	104 (d)	—	—	—
Bender Pit	ND	8/2010	Operator	104 (a)	162	—	—
Bender Pit	ND	8/2010	Operator	104 (a)	100	—	—
Lone Pine Portable	OR	7/2010	Operator	104 (a)	100	—	—
Quality Rock	OR	11/2010	Operator	104 (d)	—	—	—
Quality Rock	OR	11/2010	Operator	104 (d)	—	—	—
Quality Rock	OR	11/2010	Operator	104 (d)	—	—	—
VR Pit	WY	11/2010	Operator	104 (a)	100	—	—

* Assessments may not have yet been proposed for citations issued during the period for which the data is reported.

** Results of citations contested will be reported as one of the following: Vacated – the citation was dropped; Reduced – the severity of the violation and/or the proposed assessment amount was reduced; or No Change – the citation was enforced as issued. Results are pending for all contested citations listed above.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

The information required by this item is included in the last sentence of the second paragraph under the caption "Item 1. Election of Directors" and under the captions "Item 1. Election of Directors – Director Nominees," "Information Concerning Executive Officers," the first paragraph and the second and third sentences of the second paragraph under "Corporate Governance – Audit Committee," "Corporate Governance – Code of Conduct," the second sentence of the last paragraph under "Corporate Governance – Board Meetings and Committees" and "Section 16(a) Beneficial Ownership Reporting Compliance" in the Proxy Statement, which information is incorporated herein by reference.

Item 11. Executive Compensation

The information required by this item is included under the caption "Executive Compensation" in the Proxy Statement, which information is incorporated herein by reference.

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, 2010, 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)	882,142	(2)	$ 20.09	6,365,397	(3)(4)
Equity compensation plans not approved by stockholders (5)	228,527		13.22	2,375,474	(6)
Total	1,110,669		$ 18.68	8,740,871	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan, the Long-Term Performance-Based Incentive Plan and the Non-Employee Director Stock Compensation Plan.

(2) Includes 669,685 performance shares.

(3) In addition to being available for future issuance upon exercise of options, 357,757 shares under the Non-Employee Director Long-Term Incentive Compensation Plan may instead be issued in connection with stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards, and 5,686,140 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 321,500 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded 4,050 shares annually. A non-employee 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, 219,050 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 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, 2010, options covering 228,527 shares of common stock were outstanding under the plan and 2,156,424 shares remained available for future grant. Options covering 1,410,379 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, 2010, 4,100 shares of stock had been granted to 73 employees.

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

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required by this item is included under the captions "Related Person Transaction Disclosure," "Corporate Governance – Director Independence" and the second sentence of the third paragraph under "Corporate Governance – Board Meetings and Committees" in the Proxy Statement, which information 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" in the Proxy Statement, which information 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

MDU RESOURCES GROUP, INC.
Schedule I – Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Income

Years ended December 31,	2010	2009	2008
		(In thousands)	
Operating revenues	$ 503,658	$ 514,519	$ 618,090
Operating expenses	431,293	458,130	565,888
Operating income	72,365	56,389	52,202
Other income	5,734	6,588	1,420
Interest expense	16,664	13,996	12,609
Income before income taxes	61,435	48,981	41,013
Income taxes	17,983	13,279	12,219
Equity in earnings of subsidiaries	197,207	(158,976)	264,879
Net income	240,659	(123,274)	293,673
Dividends on preferred stocks	685	685	685
Earnings on common stock	$ 239,974	$ (123,959)	$ 292,988

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

MDU RESOURCES GROUP, INC.
Schedule I – Condensed Financial Information of Registrant (Unconsolidated)
Condensed Balance Sheets

December 31,	2010	2009
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 6,275	$ 30,103
Receivables, net	76,757	67,755
Accounts receivable from subsidiaries	27,837	33,121
Inventories	34,583	33,040
Deferred income taxes	—	346
Prepayments and other current assets	15,473	9,967
Total current assets	160,925	174,332
Investments	48,038	41,701
Investment in subsidiaries	2,336,133	2,240,332
Property, plant and equipment	1,388,128	1,277,201
Less accumulated depreciation, depletion and amortization	583,447	559,792
Net property, plant and equipment	804,681	717,409
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	119,081	107,322
Total deferred charges and other assets	123,893	112,134
Total assets	$ 3,473,670	$ 3,285,908
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings	$ 20,000	$ —
Long-term debt due within one year	107	107
Accounts payable	36,235	32,561
Accounts payable to subsidiaries	9,445	5,802
Taxes payable	8,104	14,610
Deferred income taxes	469	—
Dividends payable	30,773	29,749
Accrued compensation	11,540	13,143
Other accrued liabilities	26,002	36,419
Total current liabilities	142,675	132,391
Long-term debt	280,889	280,996
Deferred credits and other liabilities:		
Deferred income taxes	103,725	64,791
Other liabilities	253,579	236,083
Total deferred credits and other liabilities	357,304	300,874
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	15,000	15,000
Common stockholders' equity:		
Common stock		

Authorized – 500,000,000 shares, $1.00 par value				
Issued – 188,901,379 shares in 2010 and 188,389,265 shares in 2009		188,901		188,389
Other paid-in capital		1,026,349		1,015,678
Retained earnings		1,497,439		1,377,039
Accumulated other comprehensive loss		(31,261)		(20,833)
Treasury stock at cost – 538,921 shares		(3,626)		(3,626)
Total common stockholders' equity		2,677,802		2,556,647
Total stockholders' equity		2,692,802		2,571,647
Total liabilities and stockholders' equity	$	3,473,670	$	3,285,908

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

MDU RESOURCES GROUP, INC.
Schedule I – Condensed Financial Information of Registrant (Unconsolidated)
Condensed Statements of Cash Flows

Years ended December 31,	2010	2009	2008
		(In thousands)	
Net cash provided by operating activities	$ 185,887	$ 209,128	$ 138,653
Investing activities:			
Capital expenditures	(114,045)	(120,352)	(109,596)
Net proceeds from sale or disposition of property and other	625	1,039	982
Investments (in)/from and advances (to)/from subsidiaries	(1,636)	2,916	(172,006)
Disposition of investments in subsidiaries	—	20,000	121,000
Investments	(742)	(637)	5,941
Net cash used in investing activities	(115,798)	(97,034)	(153,679)
Financing activities:			
Issuance of short-term borrowings	20,000	—	—
Issuance of long-term debt	—	50,000	119,010
Repayment of long-term debt	(107)	(85,104)	(15,100)
Proceeds from issuance of common stock	4,972	65,207	15,011
Dividends paid	(119,157)	(115,023)	(108,591)
Tax benefit on stock-based compensation	375	264	1,355
Net cash provided by (used in) financing activities	(93,917)	(84,656)	11,685
Increase (decrease) in cash and cash equivalents	(23,828)	27,438	(3,341)
Cash and cash equivalents – beginning of year	30,103	2,665	6,006
Cash and cash equivalents – end of year	$ 6,275	$ 30,103	$ 2,665

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

Notes to Condensed Financial Statements

Note 1 – Summary of Significant Accounting Policies
Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income from subsidiaries is reported as equity in earnings of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. In Schedule I, amounts from discontinued operations have not been separately stated. These statements should be read in conjunction with the consolidated financial statements and notes thereto of MDU Resources Group, Inc.

Earnings (loss) per common share Please refer to the Consolidated Statements of Income of the registrant for earnings (loss) per common share. In addition, see Note 1 of Notes to Consolidated Financial Statements for information on the computation of earnings (loss) per common share.

Note 2 – Debt The Company has long-term debt obligations outstanding of $281.0 million at December 31, 2010, with annual maturities of $100,000 from 2011 to 2015 and $280.5 million scheduled to mature in years after 2015.

For more information on debt, see Note 9 of Notes to Consolidated Financial Statements.

Note 3 – Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $96.4 million, $116.3 million and $212.6 million for the years ended December 31, 2010, 2009 and 2008, respectively.

MDU RESOURCES GROUP, INC.
Schedule II – Consolidated Valuation and Qualifying Accounts

For the years ended December 31, 2010, 2009 and 2008

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:					
2010	$ 16,649	$ 5,044	$ 2,300	$ 8,709	$ 15,284
2009	13,691	12,152	1,412	10,606	16,649
2008	14,635	12,191	2,115	15,250	13,691

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

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

3. Exhibits

3(a)Restated Certificate of Incorporation of the Company, as amended, dated May 13, 2010, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

3(b)Company Bylaws, as amended and restated, on November 11, 2010**

4(a)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(b)First Supplemental Indenture, dated as of November 17, 2009, between the Company and The Bank of New York Mellon, as trustee, filed as Exhibit 4(c) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

4(c)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(d)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(e)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(f)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(g)Centennial Energy Holdings, Inc. Credit Agreement, dated December 13, 2007, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4(j) to Form 10-K for the year ended December 31, 2007, filed on February 20, 2008, in File No. 1-3480*

4(h)Consent dated November 9, 2009, under Centennial Energy Holdings, Inc. Credit Agreement, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4(i) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

4(i) MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC and the Prudential Insurance Company of America, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*

4(j) Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder, filed as Exhibit 4(b) to Form 10-Q for the quarter ended September 30, 2008, filed on November 5, 2008, in File No. 1-3480*

4(k) Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K dated August 12, 1992, in File No. 1-7196*

4(l) First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*

4(m) Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*

4(n) Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*

+10(a) Supplemental Income Security Plan, as amended and restated November 12, 2009, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(b) Directors' Compensation Policy, as amended August 12, 2010, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

+10(c) Deferred Compensation Plan for Directors, as amended May 15, 2008, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*

+10(d) Non-Employee Director Stock Compensation Plan, as amended August 12, 2010, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

+10(e) Non-Employee Director Long-Term Incentive Compensation Plan, as amended November 12, 2009, filed as Exhibit 10(f) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(f) 1998 Option Award Program, as amended November 12, 2009, filed as Exhibit 10(g) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(g) Group Genius Innovation Plan, as amended November 12, 2009, filed as Exhibit 10(h) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(h) WBI Holdings, Inc. Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(i) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(i) Knife River Corporation Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended November 16, 2009, filed as Exhibit 10(j) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(j) Long-Term Performance-Based Incentive Plan, as amended November 12, 2009, filed as Exhibit 10(k) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(k) MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended November 15, 2007, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(l) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(l) Montana-Dakota Utilities Co. Executive Incentive Compensation Plan, as amended November 15, 2007, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(m) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(m) Form of Change of Control Employment Agreement, as amended May 15, 2008, filed as Exhibit 10.1 to Form 8-K dated May 15, 2008, filed on May 20, 2008, in File No. 1-3480*

+10(n) MDU Resources Group, Inc. Executive Officers with Change of Control Employment Agreements Chart, as of December 31, 2010**

+10(o) Supplemental Executive Retirement Plan for John G. Harp, dated December 4, 2006, filed as Exhibit 10(ag) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(p) Employment Letter for John G. Harp, dated July 20, 2005, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*

+10(q) Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended March 5, 2010, filed as Exhibit 10.4 to Form 8-K dated March 5, 2010, filed on March 11, 2010, in File No. 1-3480*

+10(r) MDU Construction Services Group, Inc. Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended February 16, 2009, filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2009, filed on May 6, 2009, in File No. 1-3480*

+10(s) Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan as amended March 5, 2010, filed as Exhibit 10.2 to Form 8-K dated March 5, 2010, filed on March 11, 2010, in File No. 1-3480*

+10(t) Agreement for Termination of Change of Control Employment Agreement, dated June 15, 2010, by and between MDU Resources Group, Inc. and Terry D. Hildestad, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, in File No. 1-3480*

+10(u) Form of Notice of Expiration of Coverage Period – Change of Control Employment Agreement, dated June 15, 2010, sent by MDU Resources Group, Inc. to William E. Schneider, John G. Harp, Steven L. Bietz, David L. Goodin, William R. Connors, Mark A. Del Vecchio, Nicole A. Kivisto, Cynthia J. Norland, Paul K. Sandness, Doran N. Schwartz, and John P. Stumpf, filed as Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, in File No. 1-3480*

+10(v) Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated August 12, 2010, filed on August 17, 2010, in File No. 1-3480*

+10(w) MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, filed as Exhibit 10.2 to Form 8-K dated August 12, 2010, filed on August 17, 2010, in File No. 1-3480*

+10(x) MDU Resources Group, Inc. 401(k) Retirement Plan, as restated June 1, 2009, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2009, filed on August 7, 2009, in File No. 1-3480*

+10(y) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 2, 2009, filed as Exhibit 10(w) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(z) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 30, 2009, filed as Exhibit 10(x) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(aa) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated January 5, 2010, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2010, filed on May 5, 2010, in File No. 1-3480*

+10(ab) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 30, 2010, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2010, filed on May 5, 2010, in File No. 1-3480*

+10(ac) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated May 28, 2010, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, in File No. 1-3480*

+10(ad) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 2, 2010, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*

+10(ae) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2010**

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(a) Consent of Independent Registered Public Accounting Firm**

23(b) Consent of Ryder Scott Company, L.P.**

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**

99(a) Sales Agency Financing Agreement entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated September 5, 2008, filed on September 5, 2008, in File No. 1-3480*

99(b) Ryder Scott Company, L.P. report dated January 13, 2011**

101 The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2010, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Common Stockholders' Equity, (iv) the Consolidated Statements of Cash Flows, (v) the Notes to Consolidated Financial Statements, tagged as blocks of text, (vi) Schedule I – Condensed Financial Information of Registrant, tagged as a block of text and (vii) Schedule II – Consolidated Valuation and Qualifying Accounts, tagged as a block of text

* Incorporated herein by reference as indicated.
** Filed herewith.
+ Management contract, compensatory plan or arrangement.

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 23, 2011	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 23, 2011
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 23, 2011
/s/ Nicole A. Kivisto Nicole A. Kivisto (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 23, 2011
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 23, 2011
/s/ Thomas Everist Thomas Everist	Director	February 23, 2011
/s/ Karen B. Fagg Karen B. Fagg	Director	February 23, 2011
/s/ A. Bart Holaday A. Bart Holaday	Director	February 23, 2011
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 23, 2011
/s/ Thomas C. Knudson Thomas C. Knudson	Director	February 23, 2011

/s/ Richard H. Lewis Richard H. Lewis	Director	February 23, 2011
/s/ Patricia L. Moss Patricia L. Moss	Director	February 23, 2011
/s/ John K. Wilson John K. Wilson	Director	February 23, 2011