MDU RESOURCES GROUP INC
Form 10-K
February 24, 2012
UNITED STATES SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

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

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

(701) 530-1000
(Registrant's telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00	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 ý 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 ý.

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 ý 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 ý 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. ý

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 ý.

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2011: $4,247,855,190.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 17, 2012: 188,819,307 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2012 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
Bicent	Bicent Power LLC
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
Brazilian Transmission Lines	Company's equity method investment in the company owning ECTE, ENTE and ERTE (ownership interests in ENTE and ERTE were sold in the fourth quarter of 2010 and a portion of the ownership interest in ECTE was sold in the fourth quarter of 2011 and 2010)
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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. (7.51 percent ownership interest at December 31, 2011, 2.5 and 14.99 percent ownership interest was sold in 2011 and 2010, respectively)
EIN	Employer Identification Number
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
FIP	Funding improvement plan
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
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
JTL	JTL Group, Inc., an indirect wholly owned subsidiary of Knife River
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River (previously Morse Bros., Inc., name changed effective January 1, 2010)
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
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.
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 DEQ	Montana Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County

Montana Seventeenth Judicial 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
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon Circuit Court	Circuit Court of the State of Oregon for the County of Klamath
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
PDP	Proved developed producing
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 2012 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
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

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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 services.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings (comprised of the pipeline and energy services and the exploration and 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 ECTE is reflected in the Other category. For additional information, see Item 8 - Note 4.

As of December 31, 2011, the Company had 8,021 employees with 150 employed at MDU Resources Group, Inc., 960 at Montana-Dakota, 31 at Great Plains, 277 at Cascade, 216 at Intermountain, 625 at WBI Holdings, 2,786 at Knife River and 2,976 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, 2011.

At Montana-Dakota and Williston Basin, 362 and 87 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2015, and March 31, 2014, for Montana-Dakota and Williston Basin, respectively.

At Cascade, 169 employees are represented by the ICWU. The labor contract with the field operations group is effective through April 1, 2012.

At Intermountain, 111 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 520 of its construction materials employees. Knife River is in negotiations on 10 of its labor contracts.

MDU Construction Services has 144 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 127,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2011. 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, 2011, Montana-Dakota's net electric plant investment was $604.7 million.

The percentage of Montana-Dakota's 2011 retail electric utility operating revenues by jurisdiction is as follows: North Dakota - 61 percent; Montana - 23 percent; Wyoming - 10 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.

Through the Midwest ISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets. 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, ancillary services and capacity 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, Mandan, 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 535,761 kW in July 2011. 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 2017 will approximate 1 percent to 2 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 433.6 in 2011. PRCs are a MW of demand equivalent measure and are allocated to individual generators to meet supply obligations within the Midwest ISO. For 2011, Montana-Dakota's total PRCs, including its firm purchase power contracts, were 572.8. Montana-Dakota's peak demand supply obligation, including firm purchase power contracts, within the Midwest ISO was 524.2 PRCs for 2011. 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 capacity of 110 MW for the period June 1, 2012 to May 31, 2013, 115 MW for the period June 1, 2013 to May 31, 2014 and 120 MW for the period June 1, 2014 to May 31, 2015. Energy also will be purchased as needed, or if more economical, from the Midwest ISO market. In 2011, Montana-Dakota purchased approximately 21 percent of its net kWh needs for its interconnected system through the Midwest ISO market.

Montana-Dakota filed for an advance determination of prudence on July 7, 2011, with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities. The capacity would be a partial replacement for the contract expiring in 2015. For additional information, see Item 8 - Note 18.

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)	2011 PRCs	(a)	2011 Net Generation (kWh in thousands)	
Interconnected System:								
North Dakota:								
Coyote (b)	Steam	103,647	104,900		96.2		755,779	
Heskett	Steam	86,000	104,300		85.6		500,080	
Williston	Combustion Turbine	7,800	—		—		(68	) (c)
Glen Ullin	Heat Recovery	7,500	—		—		43,133	
Cedar Hills	Wind	19,500	19,500		3.9		59,468	
South Dakota:								
Big Stone (b)	Steam	94,111	108,600		103.3		508,058	
Montana:								
Lewis & Clark	Steam	44,000	53,100		52.1		300,782	
Glendive	Combustion Turbine	77,347	74,900		66.1		15,431	
Miles City	Combustion Turbine	23,150	23,600		20.0		218	
Diamond Willow	Wind	30,000	30,000		6.4		98,867	
		493,055	518,900		433.6		2,281,748	
Sheridan System:								
Wyoming:								
Wygen III (b)	Steam	28,000	N/A		N/A		206,589	
		521,055	518,900		433.6		2,488,337	

(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 generator's 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.

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 2016 and December 2012, respectively. 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 450,000 to 550,000 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 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.

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,	2011	2010	2009
Average cost of coal per MMBtu	$ 1.62	$ 1.55	$ 1.52
Average cost of coal per ton	$ 23.38	$ 22.60	$ 22.05

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 In North Dakota, Montana-Dakota reflects monthly increases or decreases in fuel and purchased power costs (including demand charges) and is deferring electric fuel and purchased power costs 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. A fuel adjustment clause contained in South Dakota jurisdictional electric rate schedules allows Montana-Dakota to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota to reflect increases or decreases in 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.

For information on regulatory matters, 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. Title V Operating Permits for the Glendive and Miles City combustion turbine facilities were renewed in 2011.

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 $3.6 million of environmental capital expenditures in 2011. Capital expenditures are estimated to be $15.3 million, $47.8 million and $90.0 million in 2012, 2013 and 2014, 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 2015 and 2016 of approximately $40.0 million. Projects for 2012 through 2014 will also include sulfur-dioxide, nitrogen oxide and mercury and non-mercury metals 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 846,000 residential, commercial and industrial customers in 334 communities and adjacent rural areas across eight states as of December 31, 2011, 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, 2011, the natural gas distribution operations' net natural gas distribution plant investment was $986.0 million.

The percentage of the natural gas distribution operations' 2011 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho - 33 percent; Washington - 26 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, Mandan, 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. This mechanism is expected to expire in the third quarter of 2012. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

For information on regulatory matters, see Item 8 - Note 18.

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.

The Company's 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 2011 and 2010, the natural gas distribution operations reserved $1.2 million and $6.4 million for remediation of former manufactured gas plants in Oregon and Washington, respectively. The natural gas distribution operations did not incur any other material environmental expenditures in 2011. 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 2014.

Montana-Dakota has had an economic interest in four historic manufactured gas plants and Great Plains has had an economic interest in one historic manufactured gas plant within their service territories, 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 manufactured gas plants in Washington and Oregon, as previously discussed. In addition, Cascade 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.

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 12 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, 2011, Williston Basin's net plant investment was $315.4 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. 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.

Prairielands, the energy services business of WBI Holdings, 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 exploration and production segment. Certain of the services are provided based on contracts that call for a determinable quantity of natural gas. At December 31, 2011, Prairielands has commitments to deliver fixed and determinable amounts of natural gas under these contracts of 9.2 Bcf in 2012 and the commitments to deliver natural gas for years subsequent to 2012 are immaterial. WBI Holdings currently estimates that it can adequately meet the requirements of these contracts based upon its estimated natural gas production and reserves. 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, 2011, represented 52 percent of Williston Basin's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2017. 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 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 2011 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2014.

Exploration and 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 Rocky Mountain region includes the following significant operating areas:

- Bakken areas - Fidelity significantly increased its acreage position in the Bakken oil play in 2011. The Company holds approximately 16,000 net acres in Mountrail County, North Dakota, approximately 50,000 net acres in Stark County, North Dakota, and approximately 30,000 net acres in Richland County, Montana.
- Cedar Creek Anticline - Primarily in eastern Montana, the Company has a long-held net profits interest in this oil play.
- Other exploratory oil projects - Fidelity holds approximately 75,000 net acres in the Paradox Basin in Utah, approximately 65,000 net acres in the Niobrara play in Wyoming and approximately 90,000 net acres in the Heath Shale prospect in Montana.
- Big Horn Basin - These interests include approximately 36,000 net acres and are in Wyoming, targeting oil and natural gas liquids.
- Green River Basin - These properties are primarily natural gas targets in Wyoming in which the Company holds approximately 36,000 net acres.
- Baker Field - Long-held natural gas properties in which Fidelity holds approximately 98,000 net acres in southeastern Montana and southwestern North Dakota.
- Bowdoin Field - Long-held natural gas properties in which Fidelity holds approximately 127,000 net acres in north-central Montana.
- Other - Includes the Powder River Basin and Bonny Field which Fidelity anticipates divesting of in 2012, along with various non-operated positions.

Mid-Continent/Gulf States

Fidelity's Mid-Continent/Gulf States region includes the following significant operating areas:

- South Texas - This area includes approximately 10,000 net acres in the Tabasco, Texan Gardens and Flores fields. This area has significant natural gas liquids content associated with the natural gas.
- East/Central Texas - Fidelity holds approximately 28,000 net acres.
- Other - Includes various non-operated onshore interests, as well as offshore interests in the shallow waters off the coasts of Texas and Louisiana.

Operating Information Annual net production by region for 2011 was as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total	
Rocky Mountain	34,472	2,489	49,407	74	%
Mid-Continent/Gulf States	11,126	1,011	17,189	26	

Total	45,598	3,500	66,596	100	%

Note: There are no fields that contain 15 percent or more of the Company's total proved reserves.

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.

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, 2011, were as follows:

	Gross	*	Net	**
Productive wells:				
Natural gas	3,465		2,753	
Oil	3,853		305	
Total	7,318		3,058	
Developed acreage (000's)	691		401	
Undeveloped acreage set to expire in the years (000's):				
2012	36		23	
2013	64		34	
2014	88		54	
Thereafter	765		404	
Total undeveloped acreage	953		515	

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

In most cases, acreage set to expire can be held through drilling operations or the Company can exercise extension options.

Delivery Commitments At December 31, 2011, Fidelity has commitments to deliver fixed and determinable amounts of natural gas under contracts of 5.1 Bcf in 2012 and the commitments to deliver natural gas for years subsequent to 2012 are immaterial. Fidelity does not have any material delivery commitments to deliver fixed and determinable amounts of oil at December 31, 2011.

Exploratory and Development Wells The following table reflects activities related to Fidelity's natural gas and oil wells drilled and/or tested during 2011, 2010 and 2009:

	Net Exploratory	Net Development

	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2011	4	—	4	48	—	48	52
2010	3	4	7	133	1	134	141
2009	1	2	3	104	—	104	107

At December 31, 2011, there were 57 gross (22 net) wells in the process of drilling or under evaluation, 49 of which were development wells and 8 of which were exploratory wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing 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 exploration and production industry is highly competitive. Fidelity competes with a substantial number of major and independent exploration and production 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 exploration and 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 not incurred any material capital environmental expenditures in 2011 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2014.

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, 2011. 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 proved reserves by region at December 31, 2011, are as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total		PV-10 Value * (in millions)
Rocky Mountain	280,415	27,410	444,876	76	%	$1,003.7
Mid-Continent/Gulf States	99,412	6,937	141,032	24		264.7
Total reserves	379,827	34,347	585,908	100	%	1,268.4
Discounted future income taxes						289.6
Standardized measure of discounted future net cash flows relating to proved reserves						$978.8

* 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 $384 million in backlog at December 31, 2011, compared to $420 million at December 31, 2010. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2012.

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 2009 through 2011. 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, 2011, and sales for the years ended December 31, 2011, 2010 and 2009:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves	Lease	Reserve Life
Production Area	owned	leased	owned	leased	2011	2010	2009	(000's tons)	Expiration	(years)
Anchorage, AK	—	—	1	—	137	854	891	16,563	N/A	26
Hawaii	—	6	—	—	1,527	1,412	1,940	60,683	2012-2064	37
Northern CA	—	—	9	1	1,552	1,043	1,215	48,298	2014	38
Southern CA	—	2	—	—	1,134	619	337	93,135	2035	Over 100
Portland, OR	1	3	5	3	3,106	2,521	2,718	242,614	2012-2055	87
Eugene, OR	3	4	4	1	884	1,311	1,097	170,063	2013-2046	Over 100
Central OR/WA/ID	1	2	4	4	851	1,192	1,436	105,789	2012-2077	91
Southwest OR	5	4	11	6	1,604	1,505	1,871	99,629	2012-2048	60
Central MT	—	—	1	2	758	971	1,220	29,667	2013-2027	30
Northwest MT	—	—	7	1	1,370	1,362	1,289	45,545	2020	34
Wyoming	—	—	1	2	461	447	655	13,133	2013-2019	25
Central MN	—	1	36	27	1,520	1,527	1,868	77,217	2012-2028	47
Northern MN	2	—	16	5	355	401	838	27,201	2013-2016	51
ND/SD	—	—	3	19	1,727	1,106	699	30,199	2012-2031	26

Iowa	—	1	1	8	249	642	545	7,703	2012-2020	16
Texas	1	2	1	—	1,182	1,648	1,080	21,394	2015-2025	16
Sales from other sources					6,319	4,788	4,296			
					24,736	23,349	23,995	1,088,833		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2011, are comprised of 470 million tons that are owned and 619 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 2009 through 2011 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 64 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.

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The changes in Knife River's aggregate reserves for the years ended December 31 are as follows:

	2011	2010	2009
	(000's of tons)		
Aggregate reserves:			
Beginning of year	1,107,396	1,125,491	1,145,161
Acquisitions	1,200	3,600	21,400
Sales volumes*	(18,417)	(18,561)	(19,699)
Other**	(1,346)	(3,134)	(21,371)
End of year	1,088,833	1,107,396	1,125,491

* 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 2014.

Knife River did not incur any material environmental expenditures in 2011 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 2014.

In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by Knife River - Northwest 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. For additional information, see Item 4 - Mine Safety Disclosures.

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, 2011, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2011, was approximately $308 million compared to $373 million at December 31, 2010. MDU Construction Services expects to complete a significant amount of this backlog during the year ending December 31, 2012. 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 2011 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2014.

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 exploration and 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 exploration and 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 could 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 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 results of operations, financial position and prospects, may adversely affect the market price of the Company's common stock.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. 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 materials and contracting and construction services 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 the manner 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.

The EPA finalized a rule in December 2011, that will reduce mercury and other toxic air emissions from coal- and oil-fired electric utility steam generating units. As proposed, air pollution control retrofits, such as baghouses, may be required at company-owned electric generation facilities in order to comply with the rule's emissions limits. Montana-Dakota is evaluating the impact of the final rule on its electric generation resources. Controls must be installed by approximately March 2015. One additional year may be granted by the permitting authority to install pollution controls depending on system reliability issues.

Hydraulic fracturing is an important common practice used by the Company that involves injecting water, sand and chemicals under pressure into rock formations to stimulate natural gas and oil production. The EPA is developing a study to review the potential effects of hydraulic fracturing on underground sources of drinking water; the results of that study have the potential to impact the likelihood or scope of future legislation or regulation. Other 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. While not materially impacted by current regulation, future legislation or regulation could cause the Company to experience increased compliance and operating costs, as well as delay or inhibit its ability to develop its natural gas and oil reserves.

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. The GHG "Tailoring" Rule requires new large emission sources, such as coal-fired electric generating facilities, and existing large emission sources that make modifications that increase GHG emissions 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. 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.

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.

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 materials and contracting and construction services businesses and affect ongoing operation and maintenance and construction and drilling activities for the pipeline and energy services and exploration and production businesses. In addition, severe weather can be destructive, causing outages, reduced natural gas and oil production, and/or property damage, which could require additional costs to be incurred. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial position 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 exploration and 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 position 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 multiemployer 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 70 multiemployer 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 RPs or FIPs to improve their funded status through increased contributions, reduced benefits or a combination of the two. Based on available information, the Company believes that approximately 45 percent of the multiemployer 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 multiemployer 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 multiemployer 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 multiemployer pension plans, which may have a material adverse effect on the Company's results of operations, financial position 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.

The Company's operations may be negatively impacted by cyber attacks or acts of terrorism.

The Company operates in industries that require continual operation of sophisticated information technology systems and network infrastructure. While the Company has developed procedures and processes that are designed to protect these systems, they may be vulnerable to failures or unauthorized access due to hacking, viruses, acts of terrorism or other causes. If the technology systems were to fail or be breached and these systems were not recovered in a timely manner, the Company's operational systems and infrastructure, such as the Company's electric generation, transmission and distribution facilities and its natural gas and oil production, storage and pipeline systems, may be unable to fulfill critical business functions. Any such disruption could result in a decrease in the Company's revenues and/or significant remediation costs which could have a material adverse effect on the Company's results of operations, financial position and cash flows. Additionally, because generation, transmission systems and gas pipelines are part of an interconnected system, a disruption elsewhere in the system could negatively impact the

Company's business.

The Company's business requires access to sensitive customer data in the ordinary course of business. Despite the Company's implementation of security measures, a failure or breach of a security system could compromise sensitive and confidential information and data. Such an event could result in negative publicity, remediation costs and possible legal claims and fines which could adversely affect the Company's financial results. The Company's third party service providers that perform critical business functions or have access to sensitive and confidential information and data may also be vulnerable to security breaches and other risks that could have an adverse effect on the Company.

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, which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

For information regarding mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and Item 104 of Regulation S-K, see Exhibit 95 to this Form 10-K, which is incorporated herein by reference.

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 2011 and 2010 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2011			
First quarter	$23.00	$20.11	$.1625
Second quarter	24.05	21.47	.1625
Third quarter	23.28	18.25	.1625
Fourth quarter	22.19	18.00	.1675
			$.6550
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

As of December 31, 2011, the Company's common stock was held by approximately 14,800 stockholders of record.

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. For more information on factors that may limit the Company's ability to pay dividends see Item 8 - Note 12.

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, 2011	—			
November 1 through November 30, 2011	49,050	$20.18		

December 1 through December 31, 2011	6,091	$20.52
Total	55,141	

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors and for those 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

	2011	2010	2009 *	2008 **	2007	2006
Selected Financial Data						
Operating revenues (000's):						
Electric	$225,468	$211,544	$196,171	$208,326	$193,367	$187,301
Natural gas distribution	907,400	892,708	1,072,776	1,036,109	532,997	351,988
Pipeline and energy services	278,343	329,809	307,827	532,153	447,063	443,720
Exploration and production	453,586	434,354	439,655	712,279	514,854	483,952
Construction materials and contracting	1,510,010	1,445,148	1,515,122	1,640,683	1,761,473	1,877,021
Construction services	854,389	789,100	819,064	1,257,319	1,103,215	987,582
Other	11,446	7,727	9,487	10,501	10,061	8,117
Intersegment eliminations	(190,150)	(200,695)	(183,601)	(394,092)	(315,134)	(335,142)
	$4,050,492	$3,909,695	$4,176,501	$5,003,278	$4,247,896	$4,004,539
Operating income (loss) (000's):						
Electric	$49,096	$48,296	$36,709	$35,415	$31,652	$27,716
Natural gas distribution	82,856	75,697	76,899	76,887	32,903	8,744
Pipeline and energy services	45,365	46,310	69,388	49,560	58,026	57,133
Exploration and production	133,790	143,169	(473,399)	202,954	227,728	231,802
Construction materials and contracting	51,092	63,045	93,270	62,849	138,635	156,104
Construction services	39,144	33,352	44,255	81,485	75,511	50,651
Other	5,024	858	(219)	2,887	(7,335)	(9,075)
	$406,367	$410,727	$(153,097)	$512,037	$557,120	$523,075
Earnings (loss) on common stock (000's):						
Electric	$29,258	$28,908	$24,099	$18,755	$17,700	$14,401
Natural gas distribution	38,398	36,944	30,796	34,774	14,044	5,680
Pipeline and energy services	23,082	23,208	37,845	26,367	31,408	32,126
Exploration and production	80,282	85,638	(296,730)	122,326	142,485	145,657
Construction materials and contracting	26,430	29,609	47,085	30,172	77,001	85,702
Construction services	21,627	17,982	25,589	49,782	43,843	27,851
Other	6,190	21,046	7,357	10,812	(4,380)	(4,324)
Earnings (loss) on common stock before income (loss) from discontinued operations	225,267	243,335	(123,959)	292,988	322,101	307,093
Income (loss) from discontinued operations,	(12,926)	(3,361)	—	—	109,334	7,979

net of tax	$212,341	$239,974	$(123,959)	$292,988	$431,435	$315,072

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	2011	2010	2009 *	2008 **	2007	2006
Earnings (loss) per common share before discontinued operations - diluted	$1.19	$1.29	$(.67)	$1.59	$1.76	$1.69
Discontinued operations, net of tax	(.07)	(.02)	—	—	.60	.05
	$1.12	$1.27	$(.67)	$1.59	$2.36	$1.74
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	188,905	188,229	185,175	183,807	182,902	181,392
Dividends declared per common share	$.6550	$.6350	$.6225	$.6000	$.5600	$.5234
Book value per common share	$14.62	$14.22	$13.61	$14.95	$13.80	$11.88
Market price per common share (year end)	$21.46	$20.27	$23.60	$21.58	$27.61	$25.64
Market price ratios:						
Dividend payout	58 %	50 %	N/A	38 %	24 %	30 %
Yield	3.1 %	3.2 %	2.7 %	2.9 %	2.1 %	2.1 %
Price/earnings ratio	19.2x	16.0x	N/A	13.6x	11.7x	14.7x
Market value as a percent of book value	146.8 %	142.5 %	173.4 %	144.3 %	200.1 %	215.8 %
Profitability Indicators						
Return on average common equity	7.8 %	9.1 %	(4.9)%	11.0 %	18.5 %	15.6 %
Return on average invested capital	6.3 %	7.0 %	(1.7)%	8.0 %	13.1 %	10.6 %
Fixed charges coverage, including preferred dividends	4.0x	4.1x	— ***	5.3x	6.4x	6.4x

* 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.

*** Due to the $384.4 million after-tax noncash write-down of natural gas and oil properties, earnings were insufficient by $228.7 million to cover fixed charges. If the $384.4 million after-tax noncash write-down is excluded, the coverage of fixed charges, including preferred dividends would have been 4.6 times. 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.

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.

	2011	2010	2009	2008	2007	2006
General						
Total assets (000's)	$6,556,125	$6,303,549	$5,990,952	$6,587,845	$5,592,434	$4,903,474
Total long-term debt (000's)	$1,424,678	$1,506,752	$1,499,306	$1,647,302	$1,308,463	$1,254,582
Capitalization ratios:						
Common equity	66 %	64 %	63 %	61 %	66 %	63 %
Total debt	34	36	37	39	34	37
	100 %	100 %	100 %	100 %	100 %	100 %
Electric						
Retail sales (thousand kWh)	2,878,852	2,785,710	2,663,560	2,663,452	2,601,649	2,483,248
Sales for resale (thousand kWh)	63,899	58,321	90,789	223,778	165,639	483,944
Electric system summer generating and firm purchase capability - kW (Interconnected system)	658,900	594,180	594,700	597,250	571,160	547,485
Electric system summer and firm purchase contract PRCs (Interconnected system)	572.8	553.3	*	*	*	*
Electric system peak demand obligation, including firm purchase contracts, PRCs (Interconnected system)	524.2	529.5	*	*	*	*
Demand peak - kW (Interconnected system)	535,761	525,643	525,643	525,643	525,643	485,456
Electricity produced (thousand kWh)	2,488,337	2,472,288	2,203,665	2,538,439	2,253,851	2,218,059
Electricity purchased (thousand kWh)	645,567	521,156	682,152	516,654	576,613	833,647
Average cost of fuel and purchased power per kWh	$.021	$.021	$.023	$.025	$.025	$.022
Natural Gas Distribution**						
Sales (Mdk)	103,237	95,480	102,670	87,924	52,977	34,553
Transportation (Mdk)	124,227	135,823	132,689	103,504	54,698	14,058
Degree days (% of normal)						
Montana-Dakota	101 %	98 %	104 %	103 %	93 %	87 %
Cascade	103 %	96 %	105 %	108 %	102 %	—
Intermountain	107 %	100 %	107 %	90 %	—	—
Pipeline and Energy Services						
Transportation (Mdk)	113,217	140,528	163,283	138,003	140,762	130,889
Gathering (Mdk)	66,500	77,154	92,598	102,064	92,414	87,135
Customer natural gas storage balance (Mdk)	36,021	58,784	61,506	30,598	50,219	51,477
Exploration and Production						
Production:						
Natural gas (MMcf)	45,598	50,391	56,632	65,457	62,798	62,062

Oil (MBbls)	3,500	3,262	3,111	2,808	2,365	2,041
Total production (MMcfe)	66,596	69,963	75,299	82,303	76,988	74,307
Average realized prices (including hedges):						
Natural gas (per Mcf)	$3.85	$4.36	$5.16	$7.38	$5.96	$6.03
Oil (per Bbl)	$79.43	$65.85	$47.38	$81.68	$59.26	$50.64
Average realized prices (excluding hedges):						
Natural gas (per Mcf)	$3.30	$3.57	$2.99	$7.29	$5.37	$5.62
Oil (per Bbl)	$83.30	$66.71	$49.76	$82.28	$59.53	$51.73
Proved reserves:						
Natural gas (MMcf)	379,827	448,397	448,425	604,282	523,737	538,100
Oil (MBbls)	34,347	32,867	34,216	34,348	30,612	27,100
Total reserves (MMcfe)	585,908	645,596	653,724	810,371	707,409	700,700

	2011	2010	2009	2008	2007	2006
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	24,736	23,349	23,995	31,107	36,912	45,600
Asphalt (tons)	6,709	6,279	6,360	5,846	7,062	8,273
Ready-mixed concrete (cubic yards)	2,864	2,764	3,042	3,729	4,085	4,588
Aggregate reserves (000's tons)	1,088,833	1,107,396	1,125,491	1,145,161	1,215,253	1,248,099

* 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, revolving credit facilities and the issuance from time to time of debt and equity securities. 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 building electric generation, transmission extensions, 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 and other service facilities 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.

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.

Exploration and 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 is focused on achieving a balanced commodity mix of fifty percent oil and fifty percent natural gas with its goal 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; inflationary pressure on development and operating costs; and competition from other exploration and production 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 lower margins. Continued delays in the multiple year 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.

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.

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.

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,	2011	2010	2009
	(Dollars in millions, where applicable)		
Electric	$29.2	$28.9	$24.1
Natural gas distribution	38.4	37.0	30.8
Pipeline and energy services	23.1	23.2	37.8
Exploration and production	80.3	85.6	(296.7)
Construction materials and contracting	26.4	29.6	47.1
Construction services	21.6	18.0	25.6
Other	6.2	21.0	7.3
Earnings (loss) before discontinued operations	225.2	243.3	(124.0)
Loss from discontinued operations, net of tax	(12.9)	(3.3)	—
Earnings (loss) on common stock	$212.3	$240.0	$(124.0)
Earnings (loss) per common share - basic:			
Earnings (loss) before discontinued operations	$1.19	$1.29	$(.67)
Discontinued operations, net of tax	(.07)	(.01)	—
Earnings (loss) per common share - basic	$1.12	$1.28	$(.67)
Earnings (loss) per common share - diluted:			
Earnings (loss) before discontinued operations	$1.19	$1.29	$(.67)
Discontinued operations, net of tax	(.07)	(.02)	—
Earnings (loss) per common share - diluted	$1.12	$1.27	$(.67)
Return on average common equity	7.8%	9.1%	(4.9)%

2011 compared to 2010 Consolidated earnings for 2011 decreased $27.7 million from the prior year. This decrease was due to:

- Absence of 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 an increased loss of $9.6 million (after tax) from discontinued operations, as discussed in Item 8 - Note 3. Both of these items are included in the Other category.
- Lower average realized natural gas prices, decreased natural gas production, higher depreciation, depletion and amortization expense, increased lease operating costs, higher production and property taxes and higher general and administrative expense, partially offset by higher average realized oil prices and increased oil production at the exploration and production business

Partially offsetting these decreases were higher workloads and margins in the Western region, as well as higher equipment sales and rental margins, partially offset by lower workloads and margins in the Mountain region at the construction services business.

The pipeline and energy services business experienced lower storage services revenue and decreased transportation and gathering volumes, as well as lower operation and maintenance expense, primarily related to the absence of a natural gas gathering arbitration charge of $16.5 million (after tax).

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 exploration and production business

- A $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines, as previously discussed, 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

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

Electric

Years ended December 31,	2011	2010	2009
	(Dollars in millions, where applicable)		
Operating revenues	$225.5	$211.6	$196.2
Operating expenses:			
Fuel and purchased power	64.5	63.1	65.7
Operation and maintenance	70.3	63.8	60.7
Depreciation, depletion and amortization	32.2	27.3	24.7
Taxes, other than income	9.4	9.1	8.4
	176.4	163.3	159.5
Operating income	49.1	48.3	36.7
Earnings	$29.2	$28.9	$24.1
Retail sales (million kWh)	2,878.9	2,785.7	2,663.5
Sales for resale (million kWh)	63.9	58.3	90.8
Average cost of fuel and purchased power per kWh	$.021	$.021	$.023

2011 compared to 2010 Electric earnings increased $300,000 (1 percent) compared to the prior year due to:

- Higher electric retail sales margins, primarily due to higher rates in North Dakota, Montana and Wyoming
- Increased retail sales volumes of 3 percent, primarily to residential and small commercial and industrial customers, reflecting increased customers and demand
- Lower income taxes of $3.4 million, including an income tax benefit of $1.2 million related to favorable resolution of certain income tax matters, higher production tax credits, as well as a reduction of income taxes associated with benefits

Partially offsetting these increases were:

- Higher operation and maintenance expense of $4.1 million (after tax), primarily increased benefit-related costs, as well as increased contract services
- Increased depreciation, depletion and amortization expense of $3.0 million (after tax), including the effects of higher property, plant and equipment balances
- Lower other income of $2.2 million (after tax), largely lower allowance for funds used during construction related to electric generation projects, which were placed in service in 2010
- Higher net interest expense of $1.4 million (after tax), including lower capitalized interest

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

Natural Gas Distribution

Years ended December 31,	2011	2010	2009
	(Dollars in millions, where applicable)		
Operating revenues	$907.4	$892.7	$1,072.8
Operating expenses:			
Purchased natural gas sold	594.6	589.3	757.6
Operation and maintenance	137.3	137.4	140.5
Depreciation, depletion and amortization	44.6	43.0	42.7
Taxes, other than income	48.0	47.3	55.1
	824.5	817.0	995.9
Operating income	82.9	75.7	76.9
Earnings	$38.4	$37.0	$30.8
Volumes (MMdk):			
Sales	103.3	95.5	102.7
Transportation	124.2	135.8	132.7
Total throughput	227.5	231.3	235.4
Degree days (% of normal)*			
Montana-Dakota	101 %	98 %	104 %
Cascade	103 %	96 %	105 %
Intermountain	107 %	100 %	107 %
Average cost of natural gas, including transportation, per dk	$5.76	$6.17	$7.38

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

2011 compared to 2010 The natural gas distribution business experienced an increase in earnings of $1.4 million (4 percent) compared to the prior year due to increased retail sales volumes and margins, largely resulting from colder weather than last year.

Partially offsetting this increase were:

- Higher regulated operation and maintenance expense of $3.5 million (after tax), primarily higher benefit-related costs
- Higher income taxes of $2.1 million, primarily related to the absence of a 2010 income tax benefit of $4.8 million related to a reduction in deferred income taxes associated with property, plant and equipment, partially offset by a reduction of income taxes associated with benefits
- Lower nonregulated energy-related services of $1.3 million (after tax), largely related to lower pipeline project activity
- Increased depreciation, depletion and amortization expense of $1.0 million (after tax), primarily resulting from higher property, plant and equipment balances

The previous table also reflects lower revenue and lower operation and maintenance expense related to pipeline project activity.

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, as previously discussed
- Lower operation and maintenance expense of $2.7 million (after tax), largely lower bad debt expense and benefit-related costs

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- 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.

Pipeline and Energy Services

Years ended December 31,	2011	2010	2009
	(Dollars in millions)		
Operating revenues	$278.3	$329.8	$307.8
Operating expenses:			
Purchased natural gas sold	125.3	153.9	138.8
Operation and maintenance	68.9	90.6	63.1
Depreciation, depletion and amortization	25.5	26.0	25.5
Taxes, other than income	13.2	13.0	11.0
	232.9	283.5	238.4
Operating income	45.4	46.3	69.4
Earnings	$23.1	$23.2	$37.8
Transportation volumes (MMdk)	113.2	140.5	163.3
Gathering volumes (MMdk)	66.5	77.2	92.6
Customer natural gas storage balance (MMdk):			
Beginning of period	58.8	61.5	30.6
Net injection (withdrawal)	(22.8)	(2.7)	30.9
End of period	36.0	58.8	61.5

2011 compared to 2010 Pipeline and energy services earnings decreased $100,000 largely due to:

- Lower storage services revenue of $7.1 million (after tax), largely lower storage balances
- Decreased transportation volumes of $4.6 million (after tax), largely lower volumes transported to storage resulting from decreased customer demand, as well as lower off-system transportation volumes
- Lower gathering volumes of $3.9 million (after tax), largely resulting from customers experiencing normal production declines

Partially offsetting the earnings decrease was lower operation and maintenance expense, primarily related to the absence of the natural gas gathering arbitration charge of $26.6 million ($16.5 million after tax) in 2010, as discussed in Item 8 - Note 19, partially offset by the absence of an insurance recovery that lowered costs in 2010 related to natural gas storage litigation. The natural gas storage litigation was settled in July 2009.

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), partially offset by lower costs related to natural gas storage litigation, largely due to an insurance recovery; both as previously discussed
- 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.

Exploration and Production

Years ended December 31,	2011	2010	2009
	(Dollars in millions, where applicable)		
Operating revenues:			
Natural gas	$175.6	$219.6	$292.3
Oil	278.0	214.8	147.4
	453.6	434.4	439.7
Operating expenses:			
Operation and maintenance:			
Lease operating costs	75.6	68.5	70.1
Gathering and transportation	24.3	23.5	24.0
Other	36.5	32.5	39.2
Depreciation, depletion and amortization	142.6	130.5	129.9
Taxes, other than income:			
Production and property taxes	40.8	35.5	29.1
Other	—	.7	.8
Write-down of natural gas and oil properties	—	—	620.0
	319.8	291.2	913.1
Operating income (loss)	133.8	143.2	(473.4)
Earnings (loss)	$80.3	$85.6	$(296.7)
Production:			
Natural gas (MMcf)	45,598	50,391	56,632
Oil (MBbls)	3,500	3,262	3,111
Total production (MMcfe)	66,596	69,963	75,299
Average realized prices (including hedges):			
Natural gas (per Mcf)	$3.85	$4.36	$5.16
Oil (per Bbl)	$79.43	$65.85	$47.38
Average realized prices (excluding hedges):			
Natural gas (per Mcf)	$3.30	$3.57	$2.99
Oil (per Bbl)	$83.30	$66.71	$49.76
Average depreciation, depletion and amortization rate, per equivalent Mcf	$2.04	$1.77	$1.64
Production costs, including taxes, per equivalent Mcf:			
Lease operating costs	$1.13	$.98	$.93
Gathering and transportation	.36	.34	.32
Production and property taxes	.61	.51	.39
	$2.10	$1.83	$1.64

2011 compared to 2010 Earnings at the exploration and production business decreased $5.3 million (6 percent) due to:

- Lower average realized natural gas prices of 12 percent
- Decreased natural gas production of 10 percent, largely related to normal production declines at certain properties, partially offset by increased production from the South Texas properties resulting from drilling activity, as well as production from the Green River Basin properties, which were acquired in April 2010
- Higher depreciation, depletion and amortization expense of $7.6 million (after tax), due to higher depletion rates, partially offset by lower volumes
- Increased lease operating expenses of $4.4 million (after tax) largely related to higher well maintenance costs, including higher workover costs at the Cedar Creek Anticline properties, in which the Company holds a net profits interest; costs from the Green River Basin properties, which were acquired in April 2010; as well as higher costs

resulting from increased production in the Bakken area and at the South Texas properties

- Higher production and property taxes of $3.3 million (after tax), largely resulting from higher oil prices excluding hedges
- Higher general and administrative expense of $2.0 million (after tax), largely higher payroll-related costs

Partially offsetting these decreases were:

- Higher average realized oil prices of 21 percent
- Increased oil production of 7 percent, largely related to drilling activity at the South Texas properties, as well as in the Bakken area, partially offset by normal production declines at certain properties

2010 compared to 2009 The exploration and 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

Construction Materials and Contracting

Years ended December 31,	2011	2010	2009
	(Dollars in millions)		
Operating revenues	$1,510.0	$1,445.1	$1,515.1
Operating expenses:			
Operation and maintenance	1,337.4	1,260.4	1,292.0
Depreciation, depletion and amortization	85.5	88.3	93.6
Taxes, other than income	36.0	33.4	36.2
	1,458.9	1,382.1	1,421.8
Operating income	51.1	63.0	93.3
Earnings	$26.4	$29.6	$47.1
Sales (000's):			
Aggregates (tons)	24,736	23,349	23,995
Asphalt (tons)	6,709	6,279	6,360
Ready-mixed concrete (cubic yards)	2,864	2,764	3,042

2011 compared to 2010 Earnings at the construction materials and contracting business decreased $3.2 million (11 percent) due to:

- Lower earnings of $5.8 million (after tax) resulting from lower liquid asphalt oil margins, largely due to higher asphalt oil costs
- Lower earnings of $3.3 million (after tax) resulting from lower other product line margins, largely due to lower revenues and higher costs
- Lower earnings of $2.3 million (after tax) resulting from lower ready-mixed concrete margins, primarily due to higher costs

Partially offsetting the decreases were:

- Increased construction margins of $5.4 million (after tax), largely due to increased margins and volumes in the Pacific, North Central and Mountain regions
- Lower interest expense of $2.3 million (after tax), primarily due to lower average interest rates

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.

Construction Services

Years ended December 31,	2011	2010	2009
	(In millions)		
Operating revenues	$854.4	$789.1	$819.0
Operating expenses:			
Operation and maintenance	778.5	719.7	736.3
Depreciation, depletion and amortization	11.4	12.1	12.8
Taxes, other than income	25.4	23.9	25.7
	815.3	755.7	774.8
Operating income	39.1	33.4	44.2
Earnings	$21.6	$18.0	$25.6

2011 compared to 2010 Construction services earnings increased $3.6 million (20 percent) compared to the prior year, primarily due to higher workloads and margins in the Western region, higher equipment sales and rental margins, as well as decreased general and administrative expense of $1.1 million (after tax). The earnings increase was partially offset by lower workloads and margins in the Mountain region, as well as lower margins in the Central region.

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.

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,	2011	2010	2009
	(In millions)		
Other:			
Operating revenues	$11.4	$7.7	$9.5
Operation and maintenance	4.7	4.8	8.1
Depreciation, depletion and amortization	1.6	1.6	1.3
Taxes, other than income	.1	.5	.3

Intersegment transactions:			
Operating revenues	$190.1	$200.7	$183.6
Purchased natural gas sold	147.7	175.4	156.7
Operation and maintenance	42.4	25.3	26.9

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 2012, diluted, are projected in the range of $1.00 to $1.25. The Company expects the approximate percentage of 2012 earnings per common share by quarter to be:

First quarter - 15 percent
Second quarter - 15 percent
Third quarter - 40 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 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 practicable, but not later than five years after EPA's approval of the state program. The state program was submitted January 21, 2011. The Company's share of the cost of this air quality control system is estimated at $125 million. The Company believes continuing to operate Big Stone Station with the upgrade is the best option. The Company intends to seek recovery of costs related to the above matter in electric rates charged to customers. On May 20, 2011, the Company filed for an advance determination of prudence with the NDPSC requesting advance determination that the air quality control system is reasonable and prudent, as discussed in Item 8 - Note 18.

- On July 7, 2011, the Company filed for an advance determination of prudence with the NDPSC on the construction of an 88-MW simple cycle natural gas turbine and associated facilities, as discussed in Item 8 - Note 18.

- The Company is analyzing potential projects for accommodating load growth in its industrial and agricultural sectors with company and customer-owned pipeline facilities designed to serve existing facilities currently served by fuel oil or propane, and to serve new customers.

- Currently the Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system in the Pacific Northwest.

- 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 market areas. The Company has 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 proposed project totals approximately $18 million and includes substation upgrades. Construction is underway and the project is expected to be completed by mid 2012.

Pipeline and energy services

- The Company expects lower customer storage balances in 2012 compared to 2011. In addition, the anticipated divestment of certain natural gas properties and the deferral of certain gas development activity at our exploration and production business are expected to result in gathering volumes being lower in 2012 compared to 2011. These declines are expected to be partially offset by higher transportation volumes related to growth projects placed in service in the Bakken area.

- The Company continues to pursue expansion of facilities and services offered to customers. Energy development within its

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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.

- Installation of additional compression at the Charbonneau station was completed and placed into service in September 2011, providing additional firm capacity for producers in the Bakken production area. With some additional modifications, this project has the potential of adding a total of 27 MMcf of firm capacity.

- Construction was completed in December 2011 on approximately 12 miles of high pressure transmission pipeline providing takeaway capacity from the Garden Creek processing facility in northwestern North Dakota.

- Preparations are underway for the construction of approximately 13 miles of high pressure transmission pipeline from the Stateline I and II processing facilities in northwestern North Dakota to deliver gas into the Northern Border Pipeline. The project is expected to be completed by mid 2012.

- The Company has three natural gas storage fields including the largest storage field in North America located near Baker, Montana. It continues to seek 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. Commitment on approximately 30 percent of the total potential project was received and the additional firm deliverability became available in November 2011.

Exploration and production

- The Company expects to spend approximately $400 million in capital expenditures in 2012. The Company continues its focus on returns by allocating the majority of its capital investment into the production of oil in the current commodity price environment. Its capital program reflects further exploitation of existing properties, acquisition of additional leasehold acreage, and exploratory drilling. The 2012 planned capital expenditure total does not include potential acquisitions of producing properties.

- For 2012, the Company expects a 20 percent to 30 percent increase in oil production and a 12 percent to 16 percent decrease in natural gas production. The projected decline in natural gas production is primarily the result of the anticipated divestment of certain natural gas properties and the deferral of certain natural gas development activity because of sustained low natural gas prices.

- The Company has a total of 8 drilling rigs deployed on its acreage in the Bakken, Niobrara, Texas, Paradox, Heath Shale and Big Horn areas, up from 2 rigs in the first quarter of 2011. Dependent upon results during 2012, further growth in rig activity could occur.

- Bakken Area

The Company holds a total of approximately 95,000 net acres of leaseholds.

Capital expenditures are expected to total approximately $160 million in 2012; approximately $60 million higher than the capital spent for 2011.

Mountrail County, North Dakota

The Company holds approximately 16,000 net acres of leaseholds targeting the middle Bakken and Three Forks formations.

The drilling of 17 operated and participation in various non-operated wells is expected for 2012 with approximately $75 million of capital expenditures.

Over 50 future gross well sites have been identified. Estimated gross ultimate recovery per well is 250,000 to 500,000 Bbls.

Stark County, North Dakota

The Company holds approximately 50,000 net exploratory leasehold acres, targeting the Three Forks formation.

The drilling of 7 operated wells and participation in various non-operated wells is expected for 2012 with approximately $60 million of capital expenditures.

Based on 640-acre spacing, approximately 140 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 400,000 Bbls.

Richland County, Montana

The Company has increased its acreage to approximately 30,000 net exploratory leasehold acres, targeting the Three Forks formation.

The first appraisal well is expected to be spud in the first quarter of 2012 and a total of 5 operated wells are planned for this year with approximately $25 million of capital expenditures.

Approximately 100 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 400,000 Bbls.

- Niobrara - southeastern Wyoming

The Company holds approximately 65,000 net exploratory leasehold acres.

The drilling of 4 operated wells and participation in various non-operated wells is expected for 2012 with approximately $25 million of capital expenditures.

Approximately 200 potential gross well sites have been identified based on 640-acre spacing. Estimated gross ultimate recovery rates per well are 200,000 to 300,000 Bbls.

- Paradox Basin - Cane Creek Federal Unit, Utah

The Company holds approximately 75,000 net exploratory leasehold acres.

The drilling of 4 operated wells is expected in 2012 with capital expenditures of approximately $35 million.

Approximately 70 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 500,000 Bbls.

- Texas

The Company is targeting areas that have the potential for higher liquids content with approximately $60 million of capital planned for 2012.

Plans are to drill 20 operated wells in Texas in 2012.

Approximately 50 potential gross well sites have been identified. Estimated gross ultimate recovery rates per well are 250,000 to 400,000 Bbls.

- Heath Shale

The Company holds approximately 90,000 net exploratory leasehold acres in the Heath Shale oil prospect in Montana and expects to drill between 2 and 4 wells in 2012 with capital of approximately $20 million.

- Other Opportunities

The Company continues to pursue acquisitions of additional leaseholds. Approximately $25 million of capital has been allocated to leasehold acquisitions, focusing on expansion of existing positions and new opportunities.

The remaining forecasted 2012 capital has been allocated to other operated and non-operated opportunities.

- Reserve information

The Company's combined proved natural gas and oil reserves as of December 31, 2011, were 586 Bcfe.

Reserve additions replaced annual production, however, there were approximately 60 Bcfe of negative revisions to last year's estimates. Approximately 85 percent of the negative revisions were associated with natural gas properties. Revisions of prior estimates, low natural gas prices and a change in strategy to focus on oil properties led to a significant reduction in the number of PUD reserves associated with natural gas properties.

Oil reserves are 5 percent higher than a year ago primarily the result of approximately 60 percent growth in Bakken reserves. The Company's oil reserve replacement ratio was 175 percent for 2011, excluding revisions.

Natural gas reserves are 15 percent lower primarily for the reasons mentioned previously. The biggest changes occurred in the dry gas fields of Baker and Bowdoin.

With increasing oil reserves as well as higher oil prices, the combined PV-10 value of proved oil and natural gas reserves grew by more than 10 percent year-over-year.

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

Natural Gas Index:	
NYMEX	$2.50 to $3.00 per Mcf
Crude Oil Index:	
NYMEX	$95.00 to $102.00 per Bbl

Note: Estimated prices do not reflect potential basis differentials.

- For 2012, the Company has hedged approximately 30 percent to 35 percent of its estimated natural gas production and 65 percent to 70 percent of its estimated oil production. For 2013, the Company has hedged 30 percent to 35 percent of its estimated oil production. The hedges that are in place as of February 17, 2012, are summarized in the following chart:

Commodity	Type	Index	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price (Per MMBtu/Bbl)
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
Natural Gas	Swap	Ventura	1/12 - 12/12	3,660,000	$4.87
Natural Gas	Swap	NYMEX	4/12 - 12/12	2,750,000	$3.05
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
Crude Oil	Swap	NYMEX	1/12 - 12/12	366,000	$110.30
Crude Oil	Swap	NYMEX	1/12 - 12/12	366,000	$96.00
Crude Oil	Swap	NYMEX	1/12 - 12/12	366,000	$99.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$95.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$95.30
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$100.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$100.02
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$102.00
Crude Oil	Swap	NYMEX	1/13 - 12/13	182,500	$102.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	182,500	$95.00-$117.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	182,500	$95.00-$117.00
Crude Oil	Collar	NYMEX	1/13 - 12/13	365,000	$90.00-$97.05
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

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.

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, 2011, was approximately $384 million, with 92 percent of construction backlog being public work and private representing 8 percent. Backlog a year ago was approximately $420 million. Examples of projects in work backlog include several highway paving projects, airports, bridge work, reclamation and harbor expansion projects.

- The Company has green fielded an operation in Williston in the Bakken area of North Dakota and currently has $31 million of backlog in the area. The Company is pursuing substantial growth opportunities associated with the Bakken area.

- The Company is part of a joint venture that was selected as the low bidder on the Port of Long Beach expansion. Its share of the project for this phase is expected to exceed $25 million. It also placed a new approximately 35,000 ton asphalt oil terminal into service in December 2011 in Wyoming. The Company is the primary cement provider in Hawaii and has the opportunity to supply a portion of the ready-mixed concrete and aggregate related to an approximate $5 billion multi-phased light rail project.

- Projected revenues included in the Company's 2012 earnings guidance are in the range of $1.3 billion to $1.4 billion.

- The Company anticipates margins in 2012 to be higher than 2011 levels.

- 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.

- As the country's 5th 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.

Construction services

- Work backlog as of December 31, 2011, was approximately $308 million, compared to approximately $373 million a year ago. The backlog includes a variety of projects such as substation and line construction, solar and other commercial, institutional and industrial projects including refinery work.

- Projected revenues included in the Company's 2012 earnings guidance are in the range of $700 million to $800 million.

- The Company anticipates margins in 2012 to be higher than 2011 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.

New Accounting Standards

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

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 acquisition 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 exploration and 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, 2011, 2010 and 2009, 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 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. These estimates are based on the Company's analysis of its as-filed application compared to previous regulatory 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 or in the expected return on plan assets would each increase expense by less than $1.0 million (after tax) for the year ended December 31, 2011.

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, 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 $3.4 million for the year ended December 31, 2011.

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 positions 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, 2011, the Company had cash and cash equivalents of $162.8 million and available capacity of $583.4 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 2011 increased $75.0 million from the comparable prior period. The increase was primarily due to higher deferred income taxes of $52.3 million, largely the result of bonus depreciation, as well as lower working capital requirements of $15.6 million, primarily at the electric and natural gas distribution businesses.

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 exploration and production businesses, partially offset by increased cash flows from operating activities at the electric and natural gas distribution businesses.

Investing activities Cash flows used in investing activities in 2011 increased $56.6 million from the comparable prior period due to:

- Lower proceeds from the sale of the Company's equity method investments in the Brazilian Transmission Lines of $66.3 million
- Increased ongoing capital expenditures of $47.7 million, largely at the construction materials and contracting business
- Lower proceeds from the sale or disposition of properties and other of $36.3 million, largely at the exploration and

production business

Partially offsetting the increase in cash flows used in investing activities was lower cash used for acquisitions of $104.7 million, primarily at the exploration and production business.

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 exploration and 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.

Financing activities Cash flows used in financing activities in 2011 increased $124.4 million from the comparable prior period, largely resulting from higher repayment of long-term debt and short-term borrowings of $71.5 million and $9.7 million, respectively, as well as lower issuance of short-term borrowings and long-term debt of $20.0 million and $19.9 million, respectively.

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.

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, 2011, the Pension Plans' accumulated benefit obligations exceeded these plans' assets by approximately $157.6 million. Pretax pension expense reflected in the years ended December 31, 2011, 2010 and 2009, was $3.7 million, $1.0 million and $8.2 million, respectively. The Company's pension expense is currently projected to be approximately $2.0 million to $3.0 million in 2012. Funding for the Pension Plans is actuarially determined. The minimum required contributions for 2011, 2010 and 2009 were approximately $9.3 million, $6.4 million and $7.3 million, respectively. For further information on the Company's Pension Plans, see Item 8 - Note 16.

Capital expenditures

The Company's capital expenditures for 2009 through 2011 and as anticipated for 2012 through 2014 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2009	2010	2011	2012	2013	2014
	(In millions)					
Capital expenditures:						
Electric	$115	$86	$52	$109	$141	$143
Natural gas distribution	44	75	71	108	104	74
Pipeline and energy services	70	14	45	32	67	77
Exploration and production	183	356	273	400	439	434
Construction materials and contracting	27	26	52	45	43	54
Construction services	13	15	10	12	13	12
Other	3	2	19	1	1	1
Net proceeds from sale or disposition of property and other	(27)	(79)	(41)	(9)	(1)	—
Net capital expenditures	428	495	481	698	807	795
Retirement of long-term debt	293	14	85	139	267	9
	$721	$509	$566	$837	$1,074	$804

* 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 2011, 2010 and 2009 in the preceding table include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions. The net noncash transactions were $24.0 million in 2011, $17.5 million in 2010 and immaterial in 2009.

The 2011 capital expenditures, including those for the retirement 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 2012 through 2014 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 exploration and 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. It is anticipated that all of the funds required for capital expenditures and retirement of long-term debt for the years 2012 through 2014 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.

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, 2011. 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, 2011:

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date	
			(Dollars in millions)							
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$100.0		$—	(b)	$—		5/26/15	
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)	$8.1		$—		8/11/13	
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(g)	$400.0		$—	(b)	$21.6	(d)	12/13/12	

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $100 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.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. 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 commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of the construction businesses.

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 are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. 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 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 4.0 times and 4.1 times for the 12 months ended December 31, 2011 and 2010, respectively.

Common stockholders' equity as a percent of total capitalization was 66 percent and 64 percent at December 31, 2011 and 2010, 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.

The Company currently has a shelf registration statement on file with the SEC, under which the Company may issue and sell any combination of common stock and debt securities. The Company may sell all or a portion of such securities if warranted by market conditions and the Company's capital requirements. Any public 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. The Company's board of directors currently has authorized the issuance and sale of up to an aggregate of $1.0 billion worth of such securities.

The Company's board of directors reviews this authorization on a periodic basis and the aggregate amount of securities authorized may be increased in the future.

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. 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 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 derivative instruments, long-term debt, operating leases and purchase commitments, see Item 8 - Notes 7, 9 and 19. At December 31, 2011, the Company's commitments under these obligations were as follows:

	2012	2013	2014	2015	2016	Thereafter	Total
	(In millions)						
Long-term debt	$139.3	$267.3	$9.3	$266.4	$288.4	$454.0	$1,424.7
Estimated interest payments*	84.3	69.8	62.2	58.3	37.6	245.0	557.2
Operating leases	27.8	24.3	16.4	8.6	5.8	35.9	118.8
Purchase commitments	478.0	215.9	135.8	71.1	36.7	287.0	1,224.5
Commodity derivatives	13.2	.9	—	—	—	—	14.1
Interest rate derivatives	.8	4.0	—	—	—	—	4.8
	$743.4	$582.2	$223.7	$404.4	$368.5	$1,021.9	$3,344.1

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

Not reflected in the table above are $11.2 million in uncertain tax positions. For more information, see Item 8 - Note 14.

The Company's minimum funding requirements for its defined benefit pension plans for 2012, which are not reflected in the previous table, are $15.9 million. For information on potential contributions above the minimum funding requirements, see Item 8 - Note 16.

The Company's multiemployer 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 multiemployer 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 2011, 2010 or 2009.

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, 2011. 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 2012	$5.37	10,797	$22,970
Natural gas basis swap agreements maturing in 2012	$.41	3,477	$(801)
Oil swap agreements maturing in 2012	$101.34	1,464	$3,694
Oil swap agreements maturing in 2013	$95.15	365	$(229)
Cascade			
Natural gas swap agreement maturing in 2012	$4.47	305	$(437)

	Weighted Average Floor/Ceiling Price (Per Bbl)	Forward Notional Volume (Bbl)	Fair Value
Fidelity			
Oil collar agreements maturing in 2012	$81.25/$95.88	1,464	$(10,904)
Oil collar agreements maturing in 2013	$92.50/$107.03	730	$2,061

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)

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 from time to time uses 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.

Centennial entered into interest rate swap agreements to manage a portion of its interest rate exposure on the forecasted issuance on long-term debt. The agreements call for Centennial to receive payments from or make payments to counterparties based on the difference between fixed and variable rates as specified by the interest rate swap agreements.

The following table summarizes derivative instruments entered into by Centennial as of December 31, 2011. The agreements call for Centennial to receive variable rates and pay fixed rates. The Company had no outstanding interest rate hedges at December 31, 2010.

(Notional amount and fair value in thousands)

	Weighted Average Fixed Interest Rate	Notional Amount	Fair Value
Centennial			
Interest rate swap agreement with mandatory termination date in 2012	3.15%	$10,000	$(827)
Interest rate swap agreements with mandatory termination dates in 2013	3.22%	$50,000	$(3,935)

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, 2011.

	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value
	(Dollars in millions)							
Long-term debt:								
Fixed rate	$139.3	$259.2	$9.3	$266.4	$288.4	$454.0	$1,416.6	$1,584.7
Weighted average interest rate	5.8 %	6.0 %	6.9 %	5.7 %	6.4 %	6.1 %	6.1 %	—
Variable rate	—	$8.1	—	—	—	—	$8.1	$8.1
Weighted average interest rate	—	2.5 %	—	—	—	—	2.5 %	—

Foreign currency risk

The Company's equity method investment in ECTE 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, 2011 and 2010, 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, 2011. 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, 2011.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2011, 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 President and Chief Executive Officer	Doran N. Schwartz 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, 2011 and 2010, 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, 2011. Our audits also included the financial statement schedules 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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 24, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.