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

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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.

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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.

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

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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

- 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:

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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.

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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

Terry D. Hildestad
President and Chief Executive Officer

/s/ Doran N. Schwartz

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.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2012

Report of Independent Registered Public Accounting Firm

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

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2011, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2011 of the Company and our report dated February 24, 2012 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2012

MDU RESOURCES GROUP, INC.
Consolidated Statements of Income

Years ended December 31,	2011	2010	2009
	(In thousands, except per share amounts)		
Operating revenues:			
Electric, natural gas distribution and pipeline and energy services	$1,343,714	$1,359,028	$1,504,269
Exploration and production, construction materials and contracting, construction services and other	2,706,778	2,550,667	2,672,232
Total operating revenues	4,050,492	3,909,695	4,176,501
Operating expenses:			
Fuel and purchased power	64,485	63,065	65,717
Purchased natural gas sold	572,187	567,806	739,678
Operation and maintenance:			
Electric, natural gas distribution and pipeline and energy services	275,866	291,524	263,869
Exploration and production, construction materials and contracting, construction services and other	2,215,269	2,084,377	2,143,195
Depreciation, depletion and amortization	343,395	328,843	330,542
Taxes, other than income	172,923	163,353	166,597
Write-down of natural gas and oil properties (Note 1)	—	—	620,000
Total operating expenses	3,644,125	3,498,968	4,329,598
Operating income (loss)	406,367	410,727	(153,097)
Earnings from equity method investments	4,693	30,816	8,499
Other income	6,520	8,018	9,331
Interest expense	81,354	83,011	84,099
Income (loss) before income taxes	336,226	366,550	(219,366)
Income taxes	110,274	122,530	(96,092)
Income (loss) from continuing operations	225,952	244,020	(123,274)
Loss from discontinued operations, net of tax (Note 3)	(12,926)	(3,361)	—
Net income (loss)	213,026	240,659	(123,274)
Dividends declared on preferred stocks	685	685	685
Earnings (loss) on common stock	$212,341	$239,974	$(123,959)
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)
Dividends declared per common share	$.6550	$.6350	$.6225
Weighted average common shares outstanding - basic	188,763	188,137	185,175
Weighted average common shares outstanding - diluted	188,905	188,229	185,175

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

MDU RESOURCES GROUP, INC.
Consolidated Balance Sheets

December 31,	2011	2010
(In thousands, except shares and per share amounts)		
Assets		
Current assets:		
Cash and cash equivalents	$162,772	$222,074
Receivables, net	646,251	583,743
Inventories	274,205	252,897
Deferred income taxes	40,407	32,890
Commodity derivative instruments	27,687	15,123
Prepayments and other current assets	43,316	60,441
Total current assets	1,194,638	1,167,168
Investments	109,424	103,661
Property, plant and equipment (Note 1)	7,646,222	7,218,503
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323
Net property, plant and equipment	4,285,014	4,115,180
Deferred charges and other assets:		
Goodwill (Note 5)	634,931	634,633
Other intangible assets, net (Note 5)	20,843	25,271
Other	311,275	257,636
Total deferred charges and other assets	967,049	917,540
Total assets	$6,556,125	$6,303,549
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings (Note 9)	$—	$20,000
Long-term debt due within one year	139,267	72,797
Accounts payable	337,228	301,132
Taxes payable	70,176	56,186
Dividends payable	31,794	30,773
Accrued compensation	47,804	40,121
Commodity derivative instruments	13,164	24,428
Other accrued liabilities	259,320	222,639
Total current liabilities	898,753	768,076
Long-term debt (Note 9)	1,285,411	1,433,955
Deferred credits and other liabilities:		
Deferred income taxes	769,166	672,269
Other liabilities	827,228	736,447
Total deferred credits and other liabilities	1,596,394	1,408,716
Commitments and contingencies (Notes 16, 18 and 19)		
Stockholders' equity:		
Preferred stocks (Note 11)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 12)		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 189,332,485 shares in 2011 and 188,901,379 shares in 2010	189,332	188,901
Other paid-in capital	1,035,739	1,026,349
Retained earnings	1,586,123	1,497,439
Accumulated other comprehensive loss	(47,001)	(31,261)

Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,760,567	2,677,802
Total stockholders' equity	2,775,567	2,692,802
Total liabilities and stockholders' equity	$6,556,125	$6,303,549

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

MDU RESOURCES GROUP, INC.
Consolidated Statements of Common Stockholders' Equity
Years ended December 31, 2011, 2010
and 2009

	Common Stock Shares	Common Stock Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Treasury Stock Shares	Treasury Stock Amount	Total
	(In thousands, except shares)							
Balance at December 31, 2008	184,208,283	$184,208	$938,299	$1,616,830	$10,365	(538,921)	$(3,626)	$2,746,076
Comprehensive loss:								
Net loss	—	—	—	(123,274)	—	—	—	(123,274)
Other comprehensive income (loss), net of tax -								
Net unrealized loss on derivative instruments qualifying as hedges	—	—	—	—	(51,684)	—	—	(51,684)
Postretirement liability adjustment	—	—	—	—	9,918	—	—	9,918
Foreign currency translation adjustment	—	—	—	—	10,568	—	—	10,568
Total comprehensive loss	—	—	—	—	—	—	—	(154,472)
Dividends declared on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends declared on common stock	—	—	—	(115,832)	—	—	—	(115,832)
Net tax deficit on stock-based compensation	—	—	(117)	—	—	—	—	(117)
Issuance of common stock	4,180,982	4,181	77,496	—	—	—	—	81,677
Balance at December 31, 2009	188,389,265	188,389	1,015,678	1,377,039	(20,833)	(538,921)	(3,626)	2,556,647
Comprehensive income:								

Net income	—	—	—	240,659	—	—	—	240,659
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	—	—	—	—	673	—	—	673
Postretirement liability adjustment	—	—	—	—	(5,730)	—	—	(5,730)
Foreign currency translation adjustment	—	—	—	—	(5,371)	—	—	(5,371)
Total comprehensive income	—	—	—	—	—	—	—	230,231
Dividends declared on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends declared on common stock	—	—	—	(119,574)	—	—	—	(119,574)
Tax benefit on stock-based compensation	—	—	924	—	—	—	—	924
Issuance of common stock	512,114	512	9,747	—	—	—	—	10,259
Balance at December 31, 2010	188,901,379	188,901	1,026,349	1,497,439	(31,261)	(538,921)	(3,626)	2,677,802
Comprehensive income:								
Net income	—	—	—	213,026	—	—	—	213,026
Other comprehensive income (loss), net of tax -								
Net unrealized gain on derivative instruments qualifying as hedges	—	—	—	—	7,900	—	—	7,900
Postretirement liability adjustment	—	—	—	—	(22,427)	—	—	(22,427)
Foreign currency translation adjustment	—	—	—	—	(1,295)	—	—	(1,295)

Net unrealized gains on available-for-sale investments	—	—	—	—	82	—	—	82
Total comprehensive income	—	—	—	—	—	—	—	197,286
Dividends declared on preferred stocks	—	—	—	(685)	—	—	—	(685)
Dividends declared on common stock	—	—	—	(123,657)	—	—	—	(123,657)
Net tax deficit on stock-based compensation	—	—	(909)	—	—	—	—	(909)
Issuance of common stock	431,106	431	10,299	—	—	—	—	10,730
Balance at December 31, 2011	189,332,485	$189,332	$1,035,739	$1,586,123	$(47,001)	(538,921)	$(3,626)	$2,760,567

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

MDU RESOURCES GROUP, INC.
Consolidated Statements of Cash Flows

Years ended December 31,	2011	2010	2009
	(In thousands)		
Operating activities:			
Net income (loss)	$213,026	$240,659	$(123,274)
Loss from discontinued operations, net of tax	(12,926)	(3,361)	—
Income (loss) from continuing operations	225,952	244,020	(123,274)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	343,395	328,843	330,542
Earnings, net of distributions, from equity method investments	(2,111)	(26,158)	(3,018)
Deferred income taxes	118,925	66,585	(169,764)
Write-down of natural gas and oil properties (Note 1)	—	—	620,000
Changes in current assets and liabilities, net of acquisitions:			
Receivables	(30,452)	(59,037)	132,939
Inventories	(24,226)	(4,728)	13,969
Other current assets	7,729	(7,424)	67,803
Accounts payable	(12,263)	17,833	(61,867)
Other current liabilities	33,738	12,289	44,039
Other noncurrent changes	(33,365)	(20,271)	(4,683)
Net cash provided by continuing operations	627,322	551,952	846,686
Net cash used in discontinued operations	(674)	(319)	—
Net cash provided by operating activities	626,648	551,633	846,686
Investing activities:			
Capital expenditures	(497,000)	(449,282)	(448,675)
Acquisitions, net of cash acquired	(157)	(104,812)	(6,410)
Net proceeds from sale or disposition of property and other	40,107	76,386	26,679
Investments	(10,302)	704	(3,740)
Proceeds from sale of equity method investments	2,807	69,060	—
Net cash used in continuing operations	(464,545)	(407,944)	(432,146)
Net cash provided by discontinued operations	—	—	—
Net cash used in investing activities	(464,545)	(407,944)	(432,146)
Financing activities:			
Issuance of short-term borrowings	—	20,000	10,300
Repayment of short-term borrowings	(20,000)	(10,300)	(105,100)
Issuance of long-term debt	300	20,200	145,000
Repayment of long-term debt	(85,151)	(13,668)	(292,907)
Proceeds from issuance of common stock	5,744	4,972	65,207
Dividends paid	(123,323)	(119,157)	(115,023)
Tax benefit on stock-based compensation	1,239	1,186	601
Net cash used in continuing operations	(221,191)	(96,767)	(291,922)
Net cash provided by discontinued operations	—	—	—
Net cash used in financing activities	(221,191)	(96,767)	(291,922)
Effect of exchange rate changes on cash and cash equivalents	(214)	38	782
Increase (decrease) in cash and cash equivalents	(59,302)	46,960	123,400
Cash and cash equivalents - beginning of year	222,074	175,114	51,714
Cash and cash equivalents - end of year	$162,772	$222,074	$175,114

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

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Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies
Basis of presentation
The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and energy services, exploration and production, construction materials and contracting, construction services and other. The electric, natural gas distribution, and pipeline and energy services businesses are substantially all regulated. Exploration and production, construction materials and contracting, construction services and other are nonregulated. For further descriptions of the Company's businesses, see Note 15. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

The Company's regulated businesses are subject to various state and federal agency regulations. The accounting policies followed by these businesses are generally subject to the Uniform System of Accounts of the FERC. These accounting policies differ in some respects from those used by the Company's nonregulated businesses.

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 6 for more information regarding the nature and amounts of these regulatory deferrals.

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

Management has also evaluated the impact of events occurring after December 31, 2011, up to the date of issuance of these consolidated financial statements.

Cash and cash equivalents
The Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Accounts receivable and allowance for doubtful accounts
Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. The total balance of receivables past due 90 days or more was $29.8 million and $21.6 million as of December 31, 2011 and 2010, respectively. For more information, see Percentage-of-completion method in this note.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts as of December 31, 2011 and 2010, was $12.4 million and $15.3 million, respectively.

Inventories and natural gas in storage
Inventories, other than natural gas in storage for the Company's regulated operations, were stated at the lower of average cost or market value. Natural gas in storage for the Company's regulated operations is generally carried at average cost, or cost using the last-in, first-out method. The portion of the cost of natural gas in storage expected to be

used within one year was included in inventories. Inventories at December 31 consisted of:

	2011	2010
	(In thousands)	
Aggregates held for resale	$78,518	$79,894
Materials and supplies	61,611	57,324
Natural gas in storage (current)	36,578	34,557
Asphalt oil	32,335	25,234
Merchandise for resale	32,165	30,182
Other	32,998	25,706
Total	$274,205	$252,897

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in other assets and was $50.3 million and $48.0 million at December 31, 2011 and 2010, respectively.

Investments

The Company's investments include its equity method investments as discussed in Note 4, the cash surrender value of life insurance policies, an insurance investment contract, auction rate securities, mortgage-backed securities and U.S. Treasury securities. Under the equity method, investments are initially recorded at cost and adjusted for dividends and undistributed earnings and losses. The Company has elected to measure its investment in the insurance investment contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its auction rate securities, mortgage-backed securities and U.S. Treasury securities. For more information, see Notes 8 and 16.

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets, except for exploration and production properties as described in Natural gas and oil properties in this note, the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized was $15.1 million, $17.6 million and $17.4 million in 2011, 2010 and 2009, respectively. Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method, and exploration and production properties, which are amortized on the units-of-production method based on total reserves. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

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

	2011	2010	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$546,783	$538,071	47
Distribution	255,232	243,205	36
Transmission	179,580	161,972	44
Other	86,929	83,786	13
Natural gas distribution:			
Distribution	1,257,360	1,223,239	38
Other	311,506	285,606	23
Pipeline and energy services:			
Transmission	386,227	357,395	52
Gathering	42,378	41,931	19
Storage	41,908	33,967	51
Other	36,179	33,938	29
Nonregulated:			
Pipeline and energy services:			
Gathering	198,864	203,064	17
Other	13,735	13,512	10
Exploration and production:			
Natural gas and oil properties	2,577,576	2,320,967	*
Other	37,570	35,971	9
Construction materials and contracting:			
Land	126,790	124,018	—
Buildings and improvements	67,627	65,003	20
Machinery, vehicles and equipment	902,136	899,365	12
Construction in progress	8,085	4,879	—
Aggregate reserves	395,214	393,110	**
Construction services:			
Land	4,706	4,526	—
Buildings and improvements	15,001	14,101	22
Machinery, vehicles and equipment	95,891	94,252	7
Other	9,198	10,061	4
Other:			
Land	2,837	2,837	—
Other	46,910	29,727	24
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323	
Net property, plant and equipment	$4,285,014	$4,115,180	

* Amortized on the units-of-production method based on total proved reserves at an Mcf equivalent average rate of $2.04, $1.77 and $1.64 for the years ended December 31, 2011, 2010 and 2009, respectively. Includes natural gas and oil properties accounted for under the full-cost method, of which $232.5 and $182.4 million were excluded from amortization at December 31, 2011 and 2010, respectively.

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

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. No significant impairment losses were recorded in 2011, 2010 and 2009. Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

Goodwill represents the excess of the purchase price over the fair value of identifiable net tangible and intangible assets acquired in a business combination. Goodwill is required to be tested for impairment annually, which is completed in the fourth quarter, or more frequently if events or changes in circumstances indicate that goodwill may be impaired.

The goodwill impairment test is a two-step process performed at the reporting unit level. The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach and a combination of comparable transaction multiples and peer multiples for the market approach. If the fair value of a reporting unit is less than its carrying value, step two of the goodwill impairment test is performed to determine the amount of the impairment loss, if any. The impairment is computed by comparing the implied fair value of the affected reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2011, 2010 and 2009, the fair value of each reporting unit exceeded the respective carrying value and no impairment losses were recorded. For more information on goodwill, see Note 5.

Natural gas and oil properties

The Company uses the full-cost method of accounting for its natural gas and oil production activities. Under this method, all costs incurred in the acquisition, exploration and development of natural gas and oil properties are capitalized and amortized on the units-of-production method based on total proved reserves. Any conveyances of properties, including gains or losses on abandonments of properties, are generally treated as adjustments to the cost of the properties with no gain or loss recognized.

Capitalized costs are subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, less applicable income taxes. Future net revenue was estimated based on end-of-quarter spot market prices adjusted for contracted price changes prior to the fourth quarter of 2009. Effective December 31, 2009, the Modernization of Oil and Gas Reporting rules issued by the SEC changed the pricing used to estimate reserves and associated future cash flows to SEC Defined Prices. Prior to that date, if capitalized costs exceeded the full-cost ceiling at the end of any quarter, a permanent noncash write-down was required to be charged to earnings in that quarter unless subsequent price changes eliminated or reduced an indicated write-down. Effective December 31, 2009, if capitalized costs exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

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

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

At December 31, 2011, the Company's full-cost ceiling exceeded the Company's capitalized cost. However, sustained downward movements in natural gas and oil prices subsequent to December 31, 2011, could result in a future write-down of the Company's natural gas and oil properties.

The following table summarizes the Company's natural gas and oil properties not subject to amortization at December 31, 2011, in total and by the year in which such costs were incurred:

		Year Costs Incurred			
	Total	2011	2010	2009	2008 and prior
	(In thousands)				
Acquisition	$185,773	$50,721	$71,315	$988	$62,749
Development	9,938	9,689	156	2	91
Exploration	27,439	24,389	2,710	72	268
Capitalized interest	9,312	3,539	3,096	44	2,633
Total costs not subject to amortization	$232,462	$88,338	$77,277	$1,106	$65,741

Costs not subject to amortization as of December 31, 2011, consisted primarily of unevaluated leaseholds and development costs in the Bakken area, Texas properties, Niobrara play, the Paradox Basin, the Green River Basin and the Big Horn Basin. The Company expects that the majority of these costs will be evaluated within the next five years and included in the amortization base as the properties are evaluated and/or developed.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $80.2 million and $87.3 million at December 31, 2011 and 2010, respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes revenue from exploration and production properties only on that portion of production sold and allocable to the Company's ownership interest in the related properties. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized. Costs and estimated earnings in excess of billings on uncompleted contracts of $54.3 million and $46.6 million at December 31, 2011 and 2010, respectively, represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts of $79.1 million and $65.2 million at December 31, 2011 and 2010, respectively, represent billings in excess of revenues recognized and were included in accounts payable. Amounts representing balances billed but not paid by customers under retainage provisions in contracts amounted to $51.5 million and $51.1 million at December 31, 2011 and 2010, respectively. The amounts expected to be paid within one year or less are included in receivables, net, and amounted to $49.3 million and $50.4 million at December 31, 2011 and 2010, respectively. The long-term retainage which was included in deferred charges and other assets - other was $2.2 million and $700,000 at December 31, 2011 and 2010, respectively.

Derivative instruments

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

The Company is exposed to credit-related losses in relation to derivative instruments in the event of nonperformance by counterparties.

The Company's policy generally allows the hedging of monthly forecasted sales of natural gas and oil production at Fidelity for a period up to 36 months from the time the Company enters into the hedge. The Company's policy requires that interest rate derivative instruments not exceed a period of 24 months and foreign currency derivative instruments not exceed a 12-month period. The Company's policy allows the hedging of monthly forecasted purchases of natural gas at Cascade and Intermountain for a period up to three years.

The Company's policy requires that each month as physical natural gas and oil production at Fidelity occurs and the commodity is sold, the related portion of the derivative agreement for that month's production must settle with its counterparties. Settlements represent the exchange of cash between the Company and its counterparties based on the notional quantities and prices for each month's physical delivery as specified within the agreements. The fair value of the remaining notional amounts on the derivative agreements is recorded on the balance sheet as an asset or liability measured at fair value. The Company's policy also requires settlement of natural gas derivative instruments at Cascade and Intermountain monthly and all interest rate derivative transactions must be settled over a period that will not exceed 90 days, and any foreign currency derivative transaction settlement periods may not exceed a 12-month period. The Company has policies and procedures that management believes minimize credit-risk exposure. Accordingly, the Company does not anticipate any material effect on its financial position or results of operations as a result of nonperformance by counterparties. For more information on derivative instruments, see Note 7.

The Company's swap and collar agreements are reflected at fair value. For more information, see Note 8.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 10.

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments within a period ranging from 12 to 28 months from the time such costs are paid. Natural gas costs refundable through rate adjustments were $45.1 million and $37.0 million at December 31, 2011 and 2010, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.6 million and $6.6 million at December 31, 2011 and 2010, respectively, which is included in prepayments and other current assets.

Insurance

Certain subsidiaries of the Company are insured for workers' compensation losses, subject to deductibles ranging up to $1 million per occurrence. Automobile liability and general liability losses are insured, subject to deductibles ranging up to $1 million per accident or occurrence. These subsidiaries have excess coverage above the primary automobile and general liability policies on a claims first-made and reported basis beyond the deductible levels. The subsidiaries of the Company are retaining losses up to the deductible amounts accrued on the basis of estimates of liability for claims incurred and for claims incurred but not reported.

Income taxes

The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company's assets and liabilities. Excess deferred income tax balances associated with the Company's rate-regulated activities have been recorded as a regulatory liability and are included in other liabilities. These regulatory liabilities are expected to be reflected as a reduction in future rates charged to customers in accordance with applicable regulatory procedures.

The Company uses the deferral method of accounting for investment tax credits and amortizes the credits on regulated electric and natural gas distribution plant over various periods that conform to the ratemaking treatment prescribed by the applicable state public service commissions.

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

Foreign currency translation adjustment
The functional currency of the Company's investment in ECTE, as further discussed in Note 4, is the Brazilian Real. Translation from the Brazilian Real to the U.S. dollar for assets and liabilities is performed using the exchange rate in effect at the balance sheet date. Revenues and expenses are translated on a year-to-date basis using an average of the daily exchange rates. Adjustments resulting from such translations are reported as a separate component of other comprehensive income (loss) in common stockholders' equity.

Transaction gains and losses resulting from the effect of exchange rate changes on transactions denominated in a currency other than the functional currency of the reporting entity would be recorded in income.

Earnings (loss) per common share
Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings per common share were computed by dividing earnings on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding stock options, restricted stock grants and performance share awards. In 2011 and 2010, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income was the same for both the basic and diluted earnings per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings per share calculation was as follows:

	2011	2010	2009 *
	(In thousands)		
Weighted average common shares outstanding - basic	188,763	188,137	185,175
Effect of dilutive stock options and performance share awards	142	92	—
Weighted average common shares outstanding - diluted	188,905	188,229	185,175

* Due to the loss on common stock, 825 outstanding stock options, 18 restricted stock grants and 656 performance share awards were excluded from the computation of diluted loss per common share as their effect was antidilutive.

Use of estimates
The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of long-lived assets, goodwill and natural gas and oil properties; fair values of acquired assets and liabilities under the 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. As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates.

Cash flow information
Cash expenditures for interest and income taxes were as follows:

Years ended December 31,	2011	2010	2009
	(In thousands)		
Interest, net of amount capitalized	$78,133	$80,962	$81,267
Income taxes paid (refunded), net	$(12,287)	$46,892	$39,807

For the year ended December 31, 2011, cash flows from investing activities do not include $24.0 million of capital expenditures, including amounts being financed with accounts payable, and therefore, do not have an impact on cash flows for the period.

New accounting standards
Improving Disclosure About Fair Value Measurements In January 2010, the FASB issued guidance related to improving disclosures about fair value measurements. The guidance requires separate disclosures of the amounts of transfers in and out of

Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods and were effective for the Company on January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which were effective on January 1, 2011. The guidance requires additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Amendments to Achieve Common Fair Value Measurement and Disclosure Requirements in U.S. GAAP and IFRSs
In May 2011, the FASB issued guidance on fair value measurement and disclosure requirements. The guidance generally clarifies the application of existing requirements on topics including the concepts of highest and best use and valuation premise and disclosing quantitative information about the unobservable inputs used in the measurement of instruments categorized within Level 3 of the fair value hierarchy. Additionally, the guidance includes changes on topics such as measuring fair value of financial instruments that are managed within a portfolio and additional disclosure for fair value measurements categorized within Level 3 of the fair value hierarchy. This guidance is effective for the Company on January 1, 2012. The guidance will require additional disclosures, but it will not impact the Company's results of operations, financial position or cash flows.

Presentation of Comprehensive Income In June 2011, the FASB issued guidance on the presentation of comprehensive income. This guidance eliminates the option of presenting components of other comprehensive income as part of the statement of stockholders' equity. The guidance will allow the Company the option to present the total of comprehensive income, the components of net income and the components of other comprehensive income in either a single continuous statement of comprehensive income or in two separate but consecutive statements. In December 2011, the FASB indefinitely deferred the effective date for the guidance related to the presentation of reclassifications of items out of accumulated other comprehensive income by component in both the statement in which net income is presented and the statement in which other comprehensive income is presented. The guidance, except for the portion that was indefinitely deferred, is effective for the Company on January 1, 2012, and must be applied retrospectively. The Company is evaluating the effects of this guidance on disclosure, but it will not impact the Company's results of operations, financial position or cash flows.

Disclosures about an Employer's Participation in a Multiemployer Plan In September 2011, the FASB issued guidance on an employer's participation in multiemployer benefit plans. The guidance was issued to enhance the transparency of disclosures about the significant multiemployer plans in which employers participate, the level of the employer's participation in those plans, the financial health of the plans and the nature of the employer's commitments to the plans. This guidance was effective for the Company on December 31, 2011, and must be applied retrospectively. The guidance required additional disclosures, but it did not impact the Company's results of operations, financial position or cash flows.

Comprehensive income (loss)
Comprehensive income (loss) is the sum of net income (loss) as reported and other comprehensive income (loss). The Company's other comprehensive loss resulted from gains (losses) on derivative instruments qualifying as hedges, postretirement liability adjustments, foreign currency translation adjustments and gains on available-for-sale investments. For more information on derivative instruments, see Note 7.

The components of other comprehensive loss, and their related tax effects for the years ended December 31 were as follows:

	2011	2010	2009
	(In thousands)		
Other comprehensive loss:			
Net unrealized gain (loss) on derivative instruments qualifying as hedges:			
Net unrealized gain (loss) on derivative instruments arising during the period, net of tax of $4,683, $(1,867) and $(2,509) in 2011, 2010 and 2009, respectively	$7,900	$(3,077)	$(4,094)
Less: Reclassification adjustment for gain (loss) on derivative instruments included in net income, net of tax of $0, $(2,305) and $29,170 in 2011, 2010 and 2009, respectively	—	(3,750)	47,590
Net unrealized gain (loss) on derivative instruments qualifying as hedges	7,900	673	(51,684)
Postretirement liability adjustment, net of tax of $(13,573), $(3,609) and $6,291 in 2011, 2010 and 2009, respectively	(22,427)	(5,730)	9,918
Foreign currency translation adjustment, net of tax of $(832), $(3,486) and $6,814 in 2011, 2010 and 2009, respectively	(1,295)	(5,371)	10,568
Net unrealized gains on available-for-sale investments, net of tax of $44 in 2011	82	—	—
Total other comprehensive loss	$(15,740)	$(10,428)	$(31,198)

The after-tax components of accumulated other comprehensive loss as of December 31, 2011, 2010 and 2009, were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Postretirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gains on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
	(In thousands)				
Balance at December 31, 2009	$(2,298)	$(25,163)	$6,628	$ —	$(20,833)
Balance at December 31, 2010	$(1,625)	$(30,893)	$1,257	$ —	$(31,261)
Balance at December 31, 2011	$6,275	$(53,320)	$(38)	$ 82	$(47,001)

Note 2 - Acquisitions

In 2011, a purchase price adjustment, consisting of the Company's common stock and cash, of $298,000 was made with respect to an acquisition made prior to 2011.

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

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

The acquisitions were accounted for under the acquisition method of accounting and, accordingly, the acquired assets and liabilities assumed have been recorded at their respective fair values as of the date of acquisition. The results of operations of the acquired businesses and properties are included in the financial statements since the date of each acquisition. Pro forma financial amounts reflecting the effects of the acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

Note 3 - Discontinued Operations
In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. In the fourth quarter of 2011, the Company accrued $21.0 million ($13.0 million after tax) related to the guarantee as a result of an arbitration award against CEM. In 2011, the Company also incurred legal expenses related to this matter and in the first quarter had an income tax benefit related to favorable resolution of certain tax matters. In the fourth quarter of 2010, the

Company established an accrual for an indemnification claim by Bicent. These items are reflected as discontinued operations in the consolidated financial statements and accompanying notes. Discontinued operations are included in the Other category. For further information, see Note 19.

Note 4 - Equity Method Investments
Investments in companies in which the Company has the ability to exercise significant influence over operating and financial policies are accounted for using the equity method. The Company's equity method investments at December 31, 2011 and 2010, include ECTE.

In August 2006, MDU Brasil acquired ownership interests in the Brazilian Transmission Lines. The electric transmission lines are primarily in northeastern and southern Brazil. The transmission contracts provide for revenues denominated in the Brazilian Real, annual inflation adjustments and change in tax law adjustments. The functional currency for the Brazilian Transmission Lines is the Brazilian Real.

In 2009, multiple sales agreements were signed with three separate parties for the Company to sell its ownership interests in the Brazilian Transmission Lines. In November 2010, the Company completed the sale and recognized a gain of $22.7 million ($13.8 million after tax). The Company's entire ownership interest in ENTE and ERTE and 59.96 percent of the Company's ownership interest in ECTE was sold. The remaining interest in ECTE is being purchased by one of the parties over a four-year period. In November 2011, the Company completed the sale of one-fourth of the remaining interest and recognized a gain of $1.0 million ($600,000 after tax). The gains are recorded in earnings from equity method investments on the Consolidated Statements of Income. Alusa, CEMIG and CELESC hold the remaining ownership interests in ECTE.

At December 31, 2011 and 2010, the Company's equity method investments had total assets of $111.1 million and $107.4 million, respectively, and long-term debt of $37.1 million and $30.1 million, respectively. The Company's investment in its equity method investments was approximately $9.2 million and $10.9 million, including undistributed earnings of $3.7 million and $1.9 million, at December 31, 2011 and 2010, respectively.

Note 5 - Goodwill and Other Intangible Assets
The changes in the carrying amount of goodwill for the year ended December 31, 2011, were as follows:

	Balance as of January 1, 2011 *	Goodwill Acquired During the Year **	Balance as of December 31, 2011 *
	(In thousands)		
Electric	$—	$—	$—
Natural gas distribution	345,736	—	345,736
Pipeline and energy services	9,737	—	9,737
Exploration and production	—	—	—
Construction materials and contracting	176,290	—	176,290
Construction services	102,870	298	103,168
Other	—	—	—
Total	$634,633	$298	$634,931

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

The changes in the carrying amount of goodwill for the year ended December 31, 2010, were as follows:

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

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

Other amortizable intangible assets at December 31 were as follows:

	2011	2010
	(In thousands)	
Customer relationships	$21,702	$24,942
Accumulated amortization	(10,392)	(11,625)
	11,310	13,317
Noncompete agreements	7,685	9,405
Accumulated amortization	(5,371)	(6,425)
	2,314	2,980
Other	11,442	13,217
Accumulated amortization	(4,223)	(4,243)
	7,219	8,974
Total	$20,843	$25,271

Amortization expense for intangible assets for the years ended December 31, 2011, 2010 and 2009, was $3.7 million, $4.2 million and $5.0 million, respectively. Estimated amortization expense for intangible assets is $3.8 million in 2012, $3.7 million in 2013, $3.3 million in 2014, $2.6 million in 2015, $2.1 million in 2016 and $5.3 million thereafter.

Note 6 - Regulatory Assets and Liabilities
The following table summarizes the individual components of unamortized regulatory assets and liabilities as of December 31:

	Estimated Recovery Period	*	2011	2010
			(In thousands)	
Regulatory assets:				
Pension and postretirement benefits (a)	(e)		171,492	103,818
Deferred income taxes	**		119,189	114,427
Taxes recoverable from customers (a)	—		12,433	11,961
Plant costs (a)	Over plant lives		10,256	9,964
Long-term debt refinancing costs (a)	Up to 27 years		10,112	11,101
Costs related to identifying generation development (a)	Up to 15 years		9,817	13,777
Natural gas supply derivatives (b)	Up to 1 year		437	9,359
Natural gas cost recoverable through rate adjustments (b)	Up to 28 months		2,622	6,609
Other (a) (b)	Largely within 1 year		22,651	35,225
Total regulatory assets			359,009	316,241
Regulatory liabilities:				
Plant removal and decommissioning costs (c)			289,972	276,652
Deferred income taxes**			84,963	64,017
Natural gas costs refundable through rate adjustments (d)			45,064	36,996
Taxes refundable to customers (c)			31,837	19,352
Other (c) (d)			8,393	16,080
Total regulatory liabilities			460,229	413,097
Net regulatory position			(101,220)	(96,856)

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
** Represents deferred income taxes related to regulatory assets and liabilities. The deferred income tax assets are not earning a rate of return.
(a) Included in deferred charges and other assets on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in other liabilities on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. Excluding deferred income taxes, as of December 31, 2011, approximately $216.4 million of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the balance sheet and included in the statement of income as an extraordinary item in the period in which the discontinuance of regulatory accounting occurs.

Note 7 - Derivative Instruments
Derivative instruments, including certain derivative instruments embedded in other contracts, are required to be recorded on the balance sheet as either an asset or liability measured at fair value. The Company's policy is to not

offset fair value amounts for derivative instruments and, as a result, the Company's derivative assets and liabilities are presented gross on the Consolidated Balance Sheets. Changes in the derivative instrument's fair value are recognized currently in earnings unless specific hedge accounting criteria are met. Accounting for qualifying hedges allows derivative gains and losses to offset the related results on the hedged item in the income statement and requires that a company must formally document, designate and assess the effectiveness of transactions that receive hedge accounting treatment.

In the event a derivative instrument being accounted for as a cash flow hedge does not qualify for hedge accounting because it is no longer highly effective in offsetting changes in cash flows of a hedged item; if the derivative instrument expires or is sold, terminated or exercised; or if management determines that designation of the derivative instrument as a hedge instrument is no longer appropriate, hedge accounting would be discontinued and the derivative instrument would continue to be carried at fair value with changes in its fair value recognized in earnings. In these circumstances, the net gain or loss at the time of discontinuance of hedge accounting would remain in accumulated other comprehensive income (loss) until the period or periods during which the hedged forecasted transaction affects earnings, at which time the net gain or loss would be reclassified into earnings. In the event a cash flow hedge is discontinued because it is unlikely that a forecasted transaction will occur, the derivative instrument would continue to be carried on the balance sheet at its fair value, and gains and losses that had accumulated in other comprehensive income (loss) would be recognized immediately in earnings. In the event of a sale, termination or extinguishment of a foreign currency derivative, the resulting gain or loss would be recognized immediately in earnings. The Company's policy requires approval to terminate a derivative instrument prior to its original maturity. As of December 31, 2011, the Company had no outstanding foreign currency hedges.

The Company evaluates counterparty credit risk on its derivative assets and the Company's credit risk on its derivative liabilities. As of December 31, 2011 and 2010, credit risk was not material.

Cascade and Intermountain
At December 31, 2011, Cascade held a natural gas swap agreement with total forward notional volumes of 305,000 MMBtu, which was not designated as a hedge. Cascade utilizes, and Intermountain periodically utilizes, natural gas swap agreements to manage a portion of their regulated natural gas supply portfolios in order to manage fluctuations in the price of natural gas related to core customers in accordance with authority granted by the IPUC, WUTC and OPUC. Core customers consist of residential, commercial and smaller industrial customers. The fair value of the derivative instrument must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or a liability. Periodic changes in the fair market value of the derivative instruments are recorded on the Consolidated Balance Sheets as a regulatory asset or a regulatory liability, and settlements of these arrangements are expected to be recovered through the purchased gas cost adjustment mechanism. Gains and losses on the settlements of these derivative instruments are recorded as a component of purchased natural gas sold on the Consolidated Statements of Income as they are recovered through the purchased gas cost adjustment mechanism. Under the terms of these arrangements, Cascade and Intermountain will either pay or receive settlement payments based on the difference between the fixed strike price and the monthly index price applicable to each contract. For the years ended December 31, 2011 and 2010, the change in the fair market value of the derivative instruments of $8.9 million and $18.5 million, respectively, were recorded as a decrease to regulatory assets.

Certain of Cascade's derivative instruments contain credit-risk-related contingent features that permit the counterparties to require collateralization if Cascade's derivative liability positions exceed certain dollar thresholds. The dollar thresholds in certain of Cascade's agreements are determined and may fluctuate based on Cascade's credit rating on its debt. In addition, Cascade's derivative instruments contain cross-default provisions that state if the entity fails to make payment with respect to certain of its indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of such entity's derivative instruments in liability positions. The aggregate fair value of Cascade's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $437,000. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2011, was $437,000.

Fidelity
At December 31, 2011, Fidelity held natural gas swap agreements with total forward notional volumes of 10.8 million MMBtu, natural gas basis swap agreements with total forward notional volumes of 3.5 million MMBtu, and oil swap and collar agreements with total forward notional volumes of 4.0 million Bbl, all of which were designated as cash flow hedging instruments. Fidelity utilizes these derivative instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and oil and basis differentials on its forecasted sales of natural gas and oil production.

As of December 31, 2011, the maximum term of the derivative instruments, in which the exposure to the variability in future cash flows for forecasted transactions is being hedged, is 24 months.

Centennial

At December 31, 2011, Centennial held interest rate swap agreements with a total notional amount of $60.0 million, which were designated as cash flow hedging instruments. Centennial entered into these interest rate derivative instruments to manage a portion of its interest rate exposure on the forecasted issuance of long-term debt. Centennial's interest rate swap agreements have mandatory termination dates ranging from October 2012 through June 2013.

Fidelity and Centennial

The fair value of the derivative instruments must be estimated as of the end of each reporting period and is recorded on the Consolidated Balance Sheets as an asset or liability. Changes in the fair value attributable to the effective portion of hedging instruments, net of tax, are recorded in stockholders' equity as a component of accumulated other comprehensive income (loss).

To the extent that the hedges are not effective, the ineffective portion of the changes in fair market value is recorded directly in earnings.

For the year ended December 31, 2011, $1.8 million (before tax) of hedge ineffectiveness related to natural gas and oil derivative instruments was reclassified as a gain into operating revenues and is reflected on the Consolidated Statements of Income. The amount of hedge ineffectiveness was immaterial for the years ended December 31, 2010 and 2009, and there were no components of the derivative instruments' gain or loss excluded from the assessment of hedge effectiveness. Gains and losses must be reclassified into earnings as a result of the discontinuance of cash flow hedges if it is probable that the original forecasted transactions will not occur. There were no such reclassifications into earnings as a result of the discontinuance of hedges.

Gains and losses on the natural gas and oil derivative instruments are reclassified from accumulated other comprehensive income (loss) into operating revenues on the Consolidated Statements of Income at the date the natural gas and oil quantities are settled. The proceeds received for natural gas and oil production are generally based on market prices. Gains and losses on the interest rate derivatives are reclassified from accumulated other comprehensive income (loss) into interest expense on the Consolidated Statements of Income in the same period the hedged item affects earnings. For further information regarding the gains and losses on derivative instruments qualifying as cash flow hedges that were recognized in other comprehensive income (loss) and the gains and losses reclassified from accumulated other comprehensive income (loss) into earnings, see Note 1.

Based on December 31, 2011, fair values, over the next 12 months net gains of approximately $8.7 million (after tax) are estimated to be reclassified from accumulated other comprehensive income (loss) into earnings, subject to changes in natural gas and oil market prices and interest rates, as the hedged transactions affect earnings.

Certain of Fidelity's and Centennial's derivative instruments contain cross-default provisions that state if Fidelity or any of its affiliates or Centennial fails to make payment with respect to certain indebtedness, in excess of specified amounts, the counterparties could require early settlement or termination of derivative instruments in liability positions. The aggregate fair value of Fidelity's and Centennial's derivative instruments with credit-risk-related contingent features that are in a liability position at December 31, 2011, was $18.4 million. The aggregate fair value of assets that would have been needed to settle the instruments immediately if the credit-risk-related contingent features were triggered on December 31, 2011, was $18.4 million.

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

Asset Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$27,687	$15,123
	Other assets - noncurrent	2,768	4,104
		30,455	19,227
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	—	—
	Other assets - noncurrent	—	—
		—	—
Total asset derivatives		$30,455	$19,227

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Liability Derivatives	Location on Consolidated Balance Sheets	Fair Value at December 31, 2011	Fair Value at December 31, 2010
		(In thousands)	
Designated as hedges:			
Commodity derivatives	Commodity derivative instruments	$12,727	$15,069
	Other liabilities - noncurrent	937	6,483
Interest rate derivatives	Other accrued liabilities	827	—
	Other liabilities - noncurrent	3,935	—
		18,426	21,552
Not designated as hedges:			
Commodity derivatives	Commodity derivative instruments	437	9,359
	Other liabilities - noncurrent	—	—
		437	9,359
Total liability derivatives		$18,863	$30,911

Note 8 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $38.4 million and $39.5 million as of December 31, 2011 and 2010, respectively, are classified as Investments on the Consolidated Balance Sheets. The decrease in the fair value of these investments for the year ended December 31, 2011, was $1.1 million (before tax). The increase in the fair value of these investments for the years ended December 31, 2010 and 2009, was $5.8 million (before tax) and $7.1 million (before tax), respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its remaining available-for-sale securities, which include auction rate securities, mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as Investments on the Consolidated Balance Sheets. The Company's auction rate securities approximate cost and, as a result, there are no accumulated unrealized gains or losses recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets related to these investments. Unrealized gains or losses on mortgage-backed securities and U.S. Treasury securities are recorded in accumulated other comprehensive income (loss) as discussed in Note 1. Details of available-for-sale securities were as follows:

December 31, 2011	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)			
Insurance investment contract	$31,884	$6,468	$—	$38,352
Auction rate securities	11,400	—	—	11,400
Mortgage-backed securities	8,206	95	(5)	8,296
U.S. Treasury securities	1,619	37	—	1,656
Total	$53,109	$6,600	$(5)	$59,704

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

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1) (In thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
Assets:				
Money market funds	$—	$97,500	$—	$97,500
Available-for-sale securities:				
Insurance investment contract*	—	38,352	—	38,352
Auction rate securities	—	11,400	—	11,400
Mortgage-backed securities	—	8,296	—	8,296
U.S. Treasury securities	—	1,656	—	1,656
Commodity derivative instruments - current	—	27,687	—	27,687
Commodity derivative instruments - noncurrent	—	2,768	—	2,768
Total assets measured at fair value	$—	$187,659	$—	$187,659
Liabilities:				
Commodity derivative instruments - current	$—	$13,164	$—	$13,164
Commodity derivative instruments - noncurrent	—	937	—	937
Interest rate derivative instruments - current	—	827	—	827
Interest rate derivative instruments - noncurrent	—	3,935	—	3,935
Total liabilities measured at fair value	$—	$18,863	$—	$18,863

* The insurance investment contract invests approximately 33 percent in common stock of mid-cap companies, 34 percent in common stock of small-cap companies, 32 percent in common stock of large-cap companies and 1 percent in cash and cash equivalents.

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

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

The estimated fair value of the Company's Level 2 money market funds and available-for-sale securities is determined using the market approach. The Level 2 money market funds consist of investments in short-term unsecured promissory notes and the value is based on comparable market transactions taking into consideration the credit quality of the issuer. The estimated fair value of the Company's Level 2 available-for-sale securities is based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources such as the fund itself.

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

The estimated fair value of the Company's Level 2 interest rate derivative instruments is measured using quoted market prices or pricing models using prevailing market interest rates as of the measurement date. Counterparty statements are utilized to determine the value of the interest rate derivative instruments and are reviewed and corroborated using various methodologies and significant observable inputs. The nonperformance risk of the counterparties in addition to the Company's nonperformance risk is also evaluated.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2011 and 2010, there were no significant transfers between Levels 1 and 2.

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

	2011 Carrying Amount	Fair Value	2010 Carrying Amount	Fair Value
	(In thousands)			
Long-term debt	$ 1,424,678	$ 1,592,807	$ 1,506,752	$ 1,621,184

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

Note 9 - Debt
Certain debt instruments of the Company and its subsidiaries, including those discussed below, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 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.

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

Company	Facility	Facility Limit	Amount Outstanding at December 31, 2011	Amount Outstanding at December 31, 2010	Letters of Credit at December 31, 2011	Expiration Date
		(Dollars in millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$100.0	$ — (h)	$ 20.0 (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	$ 20.2	$ —	8/11/13
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (g)	$400.0	$ — (h)	$ — (h)	$ 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 that was classified as short-term borrowings because the revolving credit agreement expired within one year.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(d) The outstanding letters of credit, as discussed in Note 19, reduce amounts available under the credit agreement.
(e) Provisions allow for an extension of up to two years upon consent of the banks.
(f) Certain provisions allow for increased borrowings, up to a maximum of $80 million.
(g) The $400 million commercial paper program is supported by a revolving credit agreement with various banks totaling $400 million (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $450 million). There were no amounts outstanding under the credit agreement.
(h) Amount outstanding under commercial paper program.

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 following includes information related to the preceding table.

Short-term borrowings

Centennial Energy Holdings, Inc. Centennial's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings as of December 31, 2011, would have been classified as short-term borrowings because the revolving credit agreement expires within one year. Any commercial paper borrowings as of December 31, 2010, would have been classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement contains customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets and on the making of certain loans and investments.

Certain of Centennial's financing agreements contain cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the applicable agreements will be in default. Certain of Centennial's financing agreements and Centennial's practices limit the amount of subsidiary indebtedness.

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

Cascade's credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the credit agreement. Certain of Cascade's financing agreements and Cascade's practices limit the amount of subsidiary indebtedness.

Long-term debt
MDU Resources Group, Inc. On May 26, 2011, the Company entered into a new revolving credit agreement, which replaced the revolving credit agreement that expired on June 21, 2011. The Company's revolving credit agreement supports its commercial paper program. Any commercial paper borrowings under this agreement would be classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The commercial paper borrowings outstanding as of December 31, 2010, were classified as short-term borrowings because the previous revolving credit agreement expired within one year.

The credit agreement contains customary covenants and provisions, including covenants of the Company not to permit, as of the end of any fiscal quarter, (A) the ratio of funded debt to total capitalization (determined on a consolidated basis) to be greater than 65 percent or (B) the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Other covenants include limitations on the sale of certain assets and on the making of certain loans and investments.

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

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

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

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

Centennial Energy Holdings, Inc. The ability to request additional borrowings under an uncommitted long-term master shelf agreement expired; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term master shelf agreement contains customary covenants and provisions, including a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent. The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's earnings before interest, taxes, depreciation and amortization to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include minimum consolidated net worth, limitation on priority debt and restrictions on the sale of certain assets and on the making of certain loans and investments.

Williston Basin Interstate Pipeline Company The ability to request additional borrowings under the uncommitted long-term private shelf agreement expired December 23, 2011; however, there is debt outstanding that is reflected in the following table. The uncommitted long-term private shelf agreement contains customary covenants and provisions, including a covenant of Williston Basin not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include limitation on priority debt and some restrictions on the sale of certain assets and the making of certain investments.

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

	2011	2010
	(In thousands)	
Senior Notes at a weighted average rate of 6.01%, due on dates ranging from May 15, 2012 to March 8, 2037	$1,287,576	$1,358,848
Medium-Term Notes at a weighted average rate of 7.72%, due on dates ranging from September 4, 2012 to March 16, 2029	81,000	81,000
Other notes at a weighted average rate of 5.24%, due on dates ranging from September 1, 2020 to February 1, 2035	40,469	41,189
Credit agreements at a weighted average rate of 2.98%, due on dates ranging from September 30, 2012 to November 30, 2038	15,633	25,715
Total long-term debt	1,424,678	1,506,752
Less current maturities	139,267	72,797
Net long-term debt	$1,285,411	$1,433,955

The amounts of scheduled long-term debt maturities for the five years and thereafter following December 31, 2011, aggregate $139.3 million in 2012; $267.3 million in 2013; $9.3 million in 2014; $266.4 million in 2015; $288.4 million in 2016 and $454.0 million thereafter.

Note 10 - Asset Retirement Obligations

The Company records obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations.

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

	2011	2010
	(In thousands)	
Balance at beginning of year	$95,970	$76,359
Liabilities incurred	3,870	8,608

Liabilities acquired	—	5,272
Liabilities settled	(10,418)	(10,740)
Accretion expense	4,466	3,588
Revisions in estimates	3,921	12,621
Other	342	262
Balance at end of year	$98,151	$95,970

The Company believes that any expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets.

The fair value of assets that are legally restricted for purposes of settling asset retirement obligations at December 31, 2011 and 2010, was $5.7 million and $5.7 million, respectively.

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

	2011	2010
	(Dollars in thousands)	
Authorized:		
Preferred -		
500,000 shares, cumulative, par value $100, issuable in series		
Preferred stock A -		
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Preference -		
500,000 shares, cumulative, without par value, issuable in series (none outstanding)		
Outstanding:		
4.50% Series - 100,000 shares	$10,000	$10,000
4.70% Series - 50,000 shares	5,000	5,000
Total preferred stocks	$15,000	$15,000

For the years 2011, 2010 and 2009, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

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

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

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

Note 12 - Common Stock
The Stock Purchase Plan provides interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan is partially

funded with the Company's common stock. From January 2009 through December 2011, purchases of shares of common stock on the open market were used to fund the Stock Purchase Plan and K-Plan. At December 31, 2011, there were 23.2 million shares of common stock reserved for original issuance under the Stock Purchase Plan and K-Plan.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. In addition, the Company and Centennial are generally restricted to paying dividends out of capital accounts or net assets. The most restrictive limitations are discussed below.

Pursuant to a covenant under a credit agreement, Centennial may only make distributions to the Company in an amount up to

100 percent of Centennial's consolidated net income after taxes for the immediately preceding fiscal year. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $2.2 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2011. In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $136 million of the Company's (excluding its subsidiaries) net assets would be restricted from use for dividend payments at December 31, 2011. In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 13 - Stock-Based Compensation
The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2011, there are 6.3 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy restricted stock, stock and performance share awards.

Total stock-based compensation expense was $3.5 million, net of income taxes of $2.2 million in 2011; $3.4 million, net of income taxes of $2.1 million in 2010; and $3.4 million, net of income taxes of $2.2 million in 2009.

As of December 31, 2011, total remaining unrecognized compensation expense related to stock-based compensation was approximately $5.5 million (before income taxes) which will be amortized over a weighted average period of 1.6 years.

Stock options
The Company had granted stock options to directors, key employees and employees. The Company has not granted stock options since 2003. Options granted to key employees automatically vested after nine years, but the plan provided for accelerated vesting based on the attainment of certain performance goals or upon a change in control of the Company, and expired ten years after the date of grant. Options granted to employees vested three years after the date of grant and expired ten years after the date of grant. Options granted to directors vested at the date of grant and expire ten years after the date of grant.

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

A summary of the status of the stock option plans at December 31, 2011, and changes during the year then ended was as follows:

	Number of Shares		Weighted Average Exercise Price
Balance at beginning of year	440,984		$13.34
Forfeited	(3,893	)	13.22
Exercised	(430,341	)	13.34
Balance at end of year	6,750		13.03
Exercisable at end of year	6,750		$13.03

Stock options outstanding as of December 31, 2011, had an aggregate intrinsic value of $57,000, and approximately six months of remaining contractual life. The aggregate intrinsic value represents the total intrinsic value (before income taxes), based on the Company's stock price on December 31, 2011, which would have been received by the option holders had all option holders exercised their options as of that date.

The Company received cash of $5.7 million, $5.0 million and $2.1 million from the exercise of stock options for the years ended December 31, 2011, 2010 and 2009, respectively. The aggregate intrinsic value of options exercised during the years ended December 31, 2011, 2010 and 2009, was $3.3 million, $2.6 million and $1.3 million, respectively.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 55,141 shares with a fair value of $1.1 million, 43,128 shares with a fair value of $849,000 and 49,649 shares with a fair value of $879,000 issued under this plan during the years ended December 31, 2011, 2010 and 2009, respectively.

Performance share awards

Since 2003, key employees of the Company have been awarded performance share awards each year. Entitlement to performance shares is based on the Company's total shareholder return over designated performance periods as measured against a selected peer group.

Target grants of performance shares outstanding at December 31, 2011, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2009	2009-2011	257,836
March 2010	2010-2012	227,009
February 2011	2011-2013	277,309

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2011, 2010 and 2009 were:

	2011	2010	2009
Grant-date fair value	$19.99	$17.40	$20.39
Blended volatility range	23.20 %- 32.18 %	25.69 %- 35.36 %	40.40 %- 50.98 %
Risk-free interest rate range	.09 %- 1.34 %	.13 %- 1.45 %	.30 %- 1.36 %
Discounted dividends per share	$1.23	$1.04	$1.79

There were no performance shares that vested in 2011. The fair value of performance share awards that vested during the years ended December 31, 2010 and 2009, was $3.5 million and $2.8 million, respectively.

A summary of the status of the performance share awards for the year ended December 31, 2011, was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	669,685	$22.19
Granted	278,252	19.99
Vested	—	—
Forfeited	(185,783)	30.55
Nonvested at end of period	762,154	$19.35

Note 14 - Income Taxes

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

	2011	2010	2009
	(In thousands)		
United States	$333,486	$336,450	$(227,021)
Foreign	2,740	30,100	7,655
Income (loss) before income taxes from continuing operations	$336,226	$366,550	$(219,366)

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

	2011	2010	2009
	(In thousands)		
Current:			
Federal	$(7,188)	$37,014	$64,389
State	778	10,589	8,284
Foreign	127	4,451	254
	(6,283)	52,054	72,927
Deferred:			
Income taxes -			
Federal	105,528	62,618	(147,607)
State	13,157	4,147	(22,370)
Investment tax credit - net	240	(180)	213
	118,925	66,585	(169,764)
Change in uncertain tax benefits	(1,048)	3,230	562
Change in accrued interest	(1,320)	661	183
Total income tax expense (benefit)	$110,274	$122,530	$(96,092)

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

	2011	2010
	(In thousands)	
Deferred tax assets:		
Regulatory matters	$119,189	$114,427
Accrued pension costs	95,260	82,085
Asset retirement obligations	26,380	24,391
Legal and environmental contingencies	21,788	13,622
Compensation-related	16,241	17,261
Other	41,055	40,307
Total deferred tax assets	319,913	292,093
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	715,482	679,809
Basis differences on natural gas and oil producing properties	210,146	152,455
Regulatory matters	84,963	64,017
Intangible asset amortization	14,307	14,843
Other	23,774	20,348
Total deferred tax liabilities	1,048,672	931,472
Net deferred income tax liability	$(728,759)	$(639,379)

As of December 31, 2011 and 2010, no valuation allowance has been recorded associated with the previously identified deferred tax assets.

The following table reconciles the change in the net deferred income tax liability from December 31, 2010, to December 31, 2011, to deferred income tax expense:

	2011
(In thousands)	
Change in net deferred income tax liability from the preceding table	$89,380
Deferred taxes associated with other comprehensive loss	9,678

Deferred taxes associated with discontinued operations	8,090
Other	11,777
Deferred income tax expense for the period	$118,925

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

Years ended December 31,	2011		2010		2009	
	Amount	%	Amount	%	Amount	%
	(Dollars in thousands)					
Computed tax at federal statutory rate	$117,679	35.0	$128,293	35.0	$(76,778)	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax benefit (expense)	10,653	3.2	10,210	2.8	(7,280)	3.3
Resolution of tax matters and uncertain tax positions	(3,906)	(1.2)	667	.2	881	(.4)
Federal renewable energy credit	(3,485)	(1.0)	(2,185)	(.6)	(1,452)	.7
Depletion allowance	(3,266)	(1.0)	(2,810)	(.8)	(2,320)	1.0
Deductible K-Plan dividends	(2,282)	(.7)	(2,309)	(.6)	(2,369)	1.1
Foreign operations	(391)	(.1)	(588)	(.2)	(1,148)	.5
Domestic production activities deduction	—	—	—	—	(856)	.4
Other	(4,728)	(1.4)	(8,748)	(2.4)	(4,770)	2.2
Total income tax expense (benefit)	$110,274	32.8	$122,530	33.4	$(96,092)	43.8

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

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $6.9 million at December 31, 2011. The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2011, was approximately $1.6 million.

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

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

	2011	2010	2009
	(In thousands)		
Balance at beginning of year	$9,378	$6,148	$5,586
Additions for tax positions of prior years	4,172	3,230	562
Settlements	(2,344)	—	—
Balance at end of year	$11,206	$9,378	$6,148

Included in the balance of unrecognized tax benefits at December 31, 2011 and 2010, were $6.6 million and $3.8 million, respectively, of tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. The amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate was $6.0 million, including approximately $1.4 million for the payment of interest and penalties at December 31, 2011, and was $7.1 million, including approximately $1.5 million for the payment of interest and penalties at December 31, 2010.

It is likely that substantially all of the unrecognized tax benefits, as well as interest, at December 31, 2011, will be settled in the next twelve months due to the anticipated settlement of federal and state audits.

For the years ended December 31, 2011, 2010 and 2009, the Company recognized approximately $780,000, $2.0 million and $190,000, respectively, in interest expense. Penalties were not material in 2011, 2010 and 2009. The Company recognized interest income of approximately $1.9 million, $20,000 and $165,000 for the years ended December 31, 2011, 2010 and 2009, respectively. The Company had accrued liabilities of approximately $970,000 and $2.3 million at December 31, 2011 and 2010, respectively, for the payment of interest.

Note 15 - Business Segment Data
The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The vast majority of the Company's operations are located within the United States. The Company also has investments in foreign countries, which largely consist of Centennial Resources' equity method investment in ECTE.

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

The pipeline and energy services segment provides natural gas transportation, underground storage and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services.

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

The construction materials and contracting segment mines aggregates and markets crushed stone, sand, gravel and related construction materials, including ready-mixed concrete, cement, asphalt, liquid asphalt and other value-added products. It also performs integrated contracting services. This segment operates in the central, southern and western United States and Alaska and Hawaii.

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

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability and automobile liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes Centennial Resources' equity method investment in ECTE.

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

	2011	2010	2009
	(In thousands)		
External operating revenues:			
Electric	$225,468	$211,544	$196,171
Natural gas distribution	907,400	892,708	1,072,776
Pipeline and energy services	210,846	254,776	235,322
	1,343,714	1,359,028	1,504,269
Exploration and production	359,873	318,570	338,425
Construction materials and contracting	1,509,538	1,445,148	1,515,122
Construction services	834,918	786,802	818,685
Other	2,449	147	—

	2,706,778	2,550,667	2,672,232
Total external operating revenues	$4,050,492	$3,909,695	$4,176,501

	2011	2010	2009
	(In thousands)		
Intersegment operating revenues:			
Electric	$—	$—	$—
Natural gas distribution	—	—	—
Pipeline and energy services	67,497	75,033	72,505
Exploration and production	93,713	115,784	101,230
Construction materials and contracting	472	—	—
Construction services	19,471	2,298	379
Other	8,997	7,580	9,487
Intersegment eliminations	(190,150)	(200,695)	(183,601)
Total intersegment operating revenues	$—	$—	$—
Depreciation, depletion and amortization:			
Electric	$32,177	$27,274	$24,637
Natural gas distribution	44,641	43,044	42,723
Pipeline and energy services	25,502	26,001	25,581
Exploration and production	142,645	130,455	129,922
Construction materials and contracting	85,459	88,331	93,615
Construction services	11,399	12,147	12,760
Other	1,572	1,591	1,304
Total depreciation, depletion and amortization	$343,395	$328,843	$330,542
Interest expense:			
Electric	$13,745	$12,216	$9,577
Natural gas distribution	29,444	28,996	30,656
Pipeline and energy services	10,516	9,064	8,896
Exploration and production	7,445	8,580	10,621
Construction materials and contracting	16,241	19,859	20,495
Construction services	4,473	4,411	4,490
Other	—	47	43
Intersegment eliminations	(510)	(162)	(679)
Total interest expense	$81,354	$83,011	$84,099
Income taxes:			
Electric	$7,242	$11,187	$8,205
Natural gas distribution	16,931	12,171	16,331
Pipeline and energy services	12,912	13,933	22,982
Exploration and production	46,298	49,034	(187,000)
Construction materials and contracting	11,227	13,822	25,940
Construction services	13,426	11,456	15,189
Other	2,238	10,927	2,261
Total income taxes	$110,274	$122,530	$(96,092)
Earnings (loss) on common stock:			
Electric	$29,258	$28,908	$24,099
Natural gas distribution	38,398	36,944	30,796
Pipeline and energy services	23,082	23,208	37,845
Exploration and production	80,282	85,638	(296,730)
Construction materials and contracting	26,430	29,609	47,085

Construction services	21,627	17,982	25,589
Other	6,190	21,046	7,357
Earnings (loss) on common stock before loss from discontinued operations	225,267	243,335	(123,959)
Loss from discontinued operations, net of tax*	(12,926)	(3,361)	—
Total earnings (loss) on common stock	$212,341	$239,974	$(123,959)

	2011 (In thousands)	2010	2009
Capital expenditures:			
Electric	$52,072	$85,787	$115,240
Natural gas distribution	70,624	75,365	43,820
Pipeline and energy services	45,556	14,255	70,168
Exploration and production	272,855	355,845	183,140
Construction materials and contracting	52,303	25,724	26,313
Construction services	9,711	14,849	12,814
Other	18,759	2,182	3,196
Net proceeds from sale or disposition of property and other	(40,857)	(78,761)	(26,679)
Total net capital expenditures	$481,023	$495,246	$428,012
Assets:			
Electric**	$672,940	$643,636	$569,666
Natural gas distribution**	1,679,091	1,632,012	1,588,144
Pipeline and energy services	526,797	523,075	538,230
Exploration and production	1,481,556	1,342,808	1,137,628
Construction materials and contracting	1,374,026	1,382,836	1,449,469
Construction services	418,519	387,627	328,895
Other***	403,196	391,555	378,920
Total assets	$6,556,125	$6,303,549	$5,990,952
Property, plant and equipment:			
Electric**	$1,068,524	$1,027,034	$941,791
Natural gas distribution**	1,568,866	1,508,845	1,456,208
Pipeline and energy services	719,291	683,807	675,199
Exploration and production	2,615,146	2,356,938	2,028,794
Construction materials and contracting	1,499,852	1,486,375	1,514,989
Construction services	124,796	122,940	116,236
Other	49,747	32,564	33,365
Less accumulated depreciation, depletion and amortization	3,361,208	3,103,323	2,872,465
Net property, plant and equipment	$4,285,014	$4,115,180	$3,894,117

* Reflected in the Other category.

** Includes allocations of common utility property.

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

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

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

Capital expenditures for 2011, 2010 and 2009 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.

Note 16 - Employee Benefit Plans

Pension and other postretirement benefit plans

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

Defined pension plan benefits to all nonunion and certain union employees hired after December 31, 2005, were discontinued. Employees that would have been eligible for defined pension plan benefits are eligible to receive additional defined contribution plan benefits. Effective January 1, 2010, all benefit and service accruals for nonunion and certain union plans were frozen. Effective June 30, 2011, all benefit and service accruals for an additional union plan were frozen. These employees will be eligible to receive additional defined contribution plan benefits.

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

Changes in benefit obligation and plan assets for the years ended December 31, 2011 and 2010, and amounts recognized in the Consolidated Balance Sheets at December 31, 2011 and 2010, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	$388,589	$352,915	$91,286	$88,151
Service cost	2,252	2,889	1,443	1,357
Interest cost	19,500	19,761	4,700	4,817
Plan participants' contributions	—	—	2,644	2,500
Amendments	—	353	—	121
Actuarial loss	62,722	34,687	17,940	3,228
Curtailment gain	(13,939)	—	—	—
Benefits paid	(23,506)	(22,016)	(7,324)	(8,888)
Benefit obligation at end of year	435,618	388,589	110,689	91,286
Change in net plan assets:				
Fair value of plan assets at beginning of year	277,598	255,327	70,610	66,984
Actual gain (loss) on plan assets	(4,718)	37,853	(872)	7,278
Employer contribution	28,626	6,434	3,027	2,736
Plan participants' contributions	—	—	2,644	2,500
Benefits paid	(23,506)	(22,016)	(7,324)	(8,888)
Fair value of net plan assets at end of year	278,000	277,598	68,085	70,610
Funded status - under	$(157,618)	$(110,991)	$(42,604)	$(20,676)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other accrued liabilities (current)	$—	$—	$(550)	$(525)
Other liabilities (noncurrent)	(157,618)	(110,991)	(42,054)	(20,151)
Net amount recognized	$(157,618)	$(110,991)	$(42,604)	$(20,676)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	$189,494	$117,840	$43,861	$20,751
Prior service cost (credit)	(632)	631	(8,615)	(11,292)
Transition obligation	—	—	2,128	4,253
Total	$188,862	$118,471	$37,374	$13,712

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

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

The accumulated benefit obligation for the defined benefit pension plans reflected previously was $435.6 million and $374.5 million at December 31, 2011 and 2010, respectively.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for the pension plans with accumulated benefit obligations in excess of plan assets at December 31 were as follows:

	2011	2010
	(In thousands)	
Projected benefit obligation	$435,618	$388,589
Accumulated benefit obligation	$435,618	$374,538
Fair value of plan assets	$278,000	$277,598

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

	Pension Benefits			Other Postretirement Benefits		
	2011	2010	2009	2011	2010	2009
	(In thousands)					
Components of net periodic benefit cost:						
Service cost	$2,252	$2,889	$8,127	$1,443	$1,357	$2,206
Interest cost	19,500	19,761	21,919	4,700	4,817	5,465
Expected return on assets	(22,809)	(23,643)	(25,062)	(5,051)	(5,512)	(5,471)
Amortization of prior service cost (credit)	45	152	605	(2,677)	(3,303)	(2,756)
Recognized net actuarial loss	4,656	2,622	2,096	753	845	970
Curtailment loss	1,218	—	1,650	—	—	—
Amortization of net transition obligation	—	—	—	2,125	2,125	2,125
Net periodic benefit cost, including amount capitalized	4,862	1,781	9,335	1,293	329	2,539
Less amount capitalized	1,196	791	1,127	(50)	(92)	330
Net periodic benefit cost	3,666	990	8,208	1,343	421	2,209
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	76,310	20,477	(29,000)	23,863	1,462	(2,314)
Prior service cost (credit)	—	353	—	—	121	(9,321)
Amortization of actuarial loss	(4,656)	(2,622)	(2,096)	(753)	(845)	(970)
Amortization of prior service (cost) credit	(1,263)	(152)	(2,255)	2,677	3,303	2,756
Amortization of net transition obligation	—	—	—	(2,125)	(2,125)	(2,125)
Total recognized in accumulated other comprehensive (income) loss	70,391	18,056	(33,351)	23,662	1,916	(11,974)
Total recognized in net periodic benefit cost and accumulated	$74,057	$19,046	$(25,143)	$25,005	$2,337	$(9,765)

other comprehensive (income)
loss

The estimated net loss and prior service credit for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $7.6 million and $85,000, respectively. The estimated net loss, prior service credit and transition obligation for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2012 are $1.9 million, $1.1 million and $2.1 million, respectively.

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

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Discount rate	4.16 %	5.26 %	4.13 %	5.21 %
Expected return on plan assets	7.75 %	7.75 %	6.75 %	6.75 %
Rate of compensation increase	N/A	4.00 %	4.00 %	4.00 %

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

	Pension Benefits		Other Postretirement Benefits	
	2011	2010	2011	2010
Discount rate	5.26 %	5.75 %	5.21 %	5.75 %
Expected return on plan assets	7.75 %	8.25 %	6.75 %	7.25 %
Rate of compensation increase	4.00 % / N/A *	4.00 %	4.00 %	4.00 %

* Effective June 30, 2011, all benefit and service accruals for a union plan were frozen. Compensation increases had previously been frozen for all other plans.

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

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

	2011	2010
Health care trend rate assumed for next year	6.0 %- 8.0 %	6.0 %- 8.5 %
Health care cost trend rate - ultimate	5.0 %- 6.0 %	5.0 %- 6.0 %
Year in which ultimate trend rate achieved	1999 - 2017	1999 - 2017

The Company's other postretirement benefit plans include health care and life insurance benefits for certain employees. The plans underlying these benefits may require contributions by the employee depending on such employee's age and years of service at retirement or the date of retirement. The accounting for the health care plans anticipates future cost-sharing changes that are consistent with the Company's expressed intent to generally increase retiree contributions each year by the excess of the expected health care cost trend rate over 6 percent.

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2011:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 171	$ (822)
Effect on postretirement benefit obligation	$ 3,175	$ (10,946)

The Company's pension assets are managed by 12 outside investment managers. The Company's other postretirement assets are managed by one outside investment manager. The Company's investment policy with respect to pension and other postretirement assets is to make investments solely in the interest of the participants and beneficiaries of the plans and for the exclusive purpose of providing benefits accrued and defraying the reasonable expenses of administration. The Company strives to maintain investment diversification to assist in minimizing the risk of large losses. The Company's policy guidelines allow for investment of funds in cash equivalents, fixed-income securities and equity securities. The guidelines prohibit investment in commodities and futures contracts, equity private placement, employer securities, leveraged or derivative securities, options, direct real estate investments, precious metals, venture capital and limited partnerships. The guidelines also prohibit short selling and margin transactions. The Company's practice is to periodically review and rebalance asset categories based on its targeted asset allocation percentage policy.

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

	Fair Value Measurements at December 31, 2011, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
	(In thousands)			
Assets:				
Cash equivalents	$2,256	$17,534	$—	$19,790
Equity securities:				
U.S. companies	99,315	—	—	99,315
International companies	35,353	—	—	35,353
Collective and mutual funds (a)	43,214	15,541	—	58,755
Corporate bonds	—	23,579	289	23,868
Mortgage-backed securities	—	22,987	—	22,987
Municipal bonds	—	9,290	—	9,290
U.S. Treasury securities	—	8,642	—	8,642
Total assets measured at fair value	$180,138	$97,573	$289	$278,000

(a) Collective and mutual funds invest approximately 26 percent in common stock of mid-cap U.S. companies, 26 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 6 percent in corporate bonds and 29 percent in other investments.

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

(a) Collective and mutual funds invest approximately 28 percent in common stock of mid-cap U.S. companies, 24 percent in common stock of large-cap U.S. companies, 13 percent in U.S. Treasuries, 11 percent in mortgage-backed securities, 10 percent in corporate bonds, 8 percent in foreign fixed-income investments and 6 percent in common stock of small-cap U.S. companies.
(b) This class includes collateral held at December 31, 2010, as a result of participation in a securities lending program. Cash collateral is invested by the trustee primarily in repurchase agreements, mutual funds and commercial paper.

The following table sets forth a summary of changes in the fair value of the pension plan's Level 3 assets for the year ended December 31, 2011:

	Fair Value Measurements Using Significant Unobservable Inputs (Level 3)		
	Corporate Bonds	Collateral Held on Loaned Securities	Total
	(In thousands)		
Balance at beginning of year	$—	$694	$694
Total realized/unrealized losses	(2)	(259)	(261)
Purchases, issuances and settlements (net)	291	(435)	(144)
Balance at end of year	$289	$—	$289

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

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

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

	Fair Value Measurements at December 31, 2011, Using Quoted Prices in Active Markets for Identical Assets (Level 1) (In thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2011
Assets:				
Cash equivalents	$59	$1,836	$—	$1,895
Equity securities:				
U.S. companies	2,098	—	—	2,098
International companies	262	—	—	262
Insurance investment contract*	—	63,830	—	63,830
Total assets measured at fair value	$2,419	$65,666	$—	$68,085

* The insurance investment contract invests approximately 49 percent in common stock of large-cap U.S. companies, 15 percent in U.S. Treasuries, 12 percent in mortgage-backed securities, 11 percent in corporate bonds, and 13 percent in other investments.

	Fair Value Measurements at December 31, 2010, Using Quoted Prices in Active Markets for Identical Assets (Level 1) (In thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2010
Assets:				
Cash equivalents	$53	$1,274	$—	$1,327
Equity securities:				
U.S. companies	2,791	—	—	2,791
International companies	353	—	—	353

Insurance investment contract*	—	66,139	—	66,139
Total assets measured at fair value	$3,197	$67,413	$—	$70,610

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

The Company expects to contribute approximately $20.2 million to its defined benefit pension plans and approximately $4.0 million to its postretirement benefit plans in 2012.

The following benefit payments, which reflect future service, as appropriate, and expected Medicare Part D subsidies are as follows:

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
	(In thousands)		
2012	$22,426	$6,892	$618
2013	22,811	7,062	656
2014	23,082	7,188	694
2015	23,508	7,298	730
2016	23,893	7,371	766
2017 - 2021	127,895	37,682	4,322

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or to their beneficiaries upon death for a 15-year period. The Company had investments of $76.9 million and $77.5 million at December 31, 2011 and 2010, respectively, consisting of equity securities of $38.4 million and $39.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $31.8 million and $30.7 million, respectively, and other investments of $6.7 million and $7.3 million, respectively. The Company anticipates using these investments to satisfy obligations under these plans. The Company's net periodic benefit cost for these plans was $8.1 million, $7.8 million and $8.8 million in 2011, 2010 and 2009, respectively. The total projected benefit obligation for these plans was $113.8 million and $99.4 million at December 31, 2011 and 2010, respectively. The accumulated benefit obligation for these plans was $105.7 million and $93.2 million at December 31, 2011 and 2010, respectively. A weighted average discount rate of 4 percent and 5.11 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4 percent at December 31, 2011 and 2010, were used to determine benefit obligations. A discount rate of 5.11 percent and 5.75 percent at December 31, 2011 and 2010, respectively, and a rate of compensation increase of 4 percent at December 31, 2011 and 2010, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $5.2 million in 2012; $5.9 million in 2013; $5.8 million in 2014; $6.9 million in 2015; $6.8 million in 2016 and $38.3 million for the years 2017 through 2021.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees. Costs incurred by the Company under these plans were $27.1 million in 2011, $24.4 million in 2010 and $20.5 million in 2009.

Multiemployer plans

The Company contributes to a number of multiemployer defined benefit pension plans under the terms of collective-bargaining agreements that cover its union-represented employees. The risks of participating in these multiemployer plans are different from single-employer plans in the following aspects:

- Assets contributed to the multiemployer plan by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers

- If the Company chooses to stop participating in some of its multiemployer plans, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans for the annual period ended December 31, 2011, is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2011 and 2010 is for the plan's year-end at December 31, 2010, and December 31, 2009, respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded. From 2009 to 2010 and 2010 to 2011, contributions by the Company to multiemployer defined benefit pension plans decreased as a result of a reduction in covered employees corresponding to a decline in overall business.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2011	2010	FIP/RP Status Pending/Implemented	Contributions 2011	2010	2009	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Edison Pension Plan	93-6061681-001	Green	Green	No	$2,700	$1,933	$1,627	No	12/31/2012
IBEW Local 38 Pension Plan	34-6574238-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	1,469	1,277	594	No	*
IBEW Local No. 82 Pension Plan	31-6127268-001	Red as of 6/30/2011	Red as of 6/30/2010	Implemented	1,331	1,569	1,197	No	*
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2011	Red as of 2/28/2010	Implemented	722	781	641	No	8/31/2012
Laborers Pension Trust Fund for Northern California	94-6277608-001	Yellow as of 5/31/2011	Yellow as of 5/31/2010	Implemented	628	413	325	No	6/30/2012*
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2011	Yellow as of 4/30/2010	Implemented	776	679	469	No	*
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	4,841	4,826	5,462	No	5/31/2014*
OE Pension Trust Fund	94-6090764-001	Yellow	Yellow	Implemented	1,367	1,035	1,061	No	3/31/2016*
Other funds					15,324	17,763	21,103		
Total contributions					$29,158	$30,276	$32,479		

* Plan includes collective bargaining agreements which have expired. The agreements contain provisions that automatically renew the existing contracts in lieu of a new negotiated collective bargaining agreement.

The Company was listed in the plans' Forms 5500 as providing more than 5 percent of the total contributions for the following plans and plan years:

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Defined Benefit Pension Plan of AGC-IUOE Local 701 Pension Trust Fund	2010 and 2009
Edison Pension Plan	2010 and 2009

Eighth District Electrical Pension Fund	2010 and 2009
IBEW Local 38 Pension Plan	2010 and 2009
IBEW Local No. 82 Pension Plan	2010 and 2009
IBEW Local Union No. 357 Pension Plan A	2010 and 2009
IBEW Local 648 Pension Plan	2010 and 2009
Idaho Plumbers and Pipefitters Pension Plan	2010 and 2009
Laborers AGC Pension Trust of Montana	2009
Local Union No. 124 IBEW Pension Trust Fund	2010 and 2009
Local Union 212 IBEW Pension Trust Fund	2010 and 2009
Minnesota Teamsters Constr Division Pension Fund	2010 and 2009
Operating Engineers Local 800 and Wyoming Contractors Association, Inc. Pension Plan for Wyoming	2010 and 2009
Plumbers & Pipefitters Local 162 Pension Fund	2010 and 2009
Southwest Marine Pension Trust	2009

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $24.0 million,

$24.7 million and $28.9 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Amounts contributed in 2011, 2010 and 2009 to defined contribution multiemployer plans were $15.3 million, $15.4 million and $16.4 million, respectively.

Note 17 - Jointly Owned Facilities
The consolidated financial statements include the Company's 22.7 percent, 25.0 percent and 25.0 percent ownership interests in the assets, liabilities and expenses of the Big Stone Station, Coyote Station and Wygen III, respectively. Each owner of the stations is responsible for financing its investment in the jointly owned facilities.

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses in the Consolidated Statements of Income.

At December 31, the Company's share of the cost of utility plant in service and related accumulated depreciation for the stations was as follows:

	2011	2010
	(In thousands)	
Big Stone Station:		
Utility plant in service	$63,715	$60,404
Less accumulated depreciation	42,475	41,136
	$21,240	$19,268
Coyote Station:		
Utility plant in service	$131,719	$131,395
Less accumulated depreciation	86,788	84,710
	$44,931	$46,685
Wygen III:*		
Utility plant in service	$63,300	$63,215
Less accumulated depreciation	2,106	838
	$61,194	$62,377

* Began commercial operation on April 1, 2010.

Note 18 - Regulatory Matters and Revenues Subject to Refund
On May 20, 2011, Montana-Dakota filed an application with the NDPSC requesting advance determination of prudence that the addition of the air quality control system at the Big Stone Station, to comply with the Clean Air Act and the South Dakota Regional Haze Implementation Plan, is reasonable and prudent. A hearing was held on November 29, 2011. On January 9, 2012, Montana-Dakota, Otter Tail Corporation and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the air quality control system is prudent. An order is expected in the first quarter of 2012.

On July 7, 2011, Montana-Dakota 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 projected to be in service in 2015. The turbine will be located on company-owned property that is adjacent to Montana-Dakota's Heskett Generating Station near Mandan, North Dakota, and would be used to meet the capacity requirements of Montana-Dakota's integrated electric system service customers. The capacity will be a partial replacement for third party contract capacity expiring in 2015. Project cost is estimated to be $85.6 million. A hearing was held on January 10, 2012. On January 18, 2012, Montana-Dakota and the NDPSC Advocacy Staff filed a settlement agreement with the NDPSC that reflects agreement that the natural gas turbine is prudent and a certificate of need should be approved. An order is expected in the first quarter of 2012.

On November 15, 2011, the MNPUC issued a Notice of Investigation; Opportunity to Respond and Comment to investigate whether Great Plains' rates are unreasonable and whether Great Plains should be ordered to initiate a general rate proceeding as Great Plains has earned in excess of its authorized return and the excess earnings are likely to continue into the future. On December 2, 2011, Great Plains responded to the MNPUC's Notice. On January 30, 2012, the MNPUC issued an order that found that the reasonableness of Great Plains' rates had not been resolved to the MNPUC's satisfaction and requires Great Plains to initiate a rate proceeding within 180 days of the order. In addition, the MNPUC encouraged Great Plains, the Minnesota Department of Commerce and any other interested parties to enter into settlement discussions with the requirement that the interested parties file a report on the status of settlement discussions within 60 days of the order.

Note 19 - Commitments and Contingencies
The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, where feasible, an estimate of the possible loss. The Company had accrued liabilities of $64.1 million and $45.3 million for contingencies related to litigation and environmental matters as of December 31, 2011 and 2010, respectively, which includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation
Guarantee Obligation Under a Construction Contract Centennial guaranteed CEM's obligations under a construction contract with LPP for a 550-MW combined-cycle electric generating facility near Hobbs, New Mexico. Centennial Resources sold CEM in July 2007 to Bicent, which provided a $10 million bank letter of credit to Centennial in support of the guarantee obligation, which letter of credit expired in November 2010. In February 2009, Centennial received a Notice and Demand from LPP under the guarantee agreement alleging that CEM did not meet certain of its obligations under the construction contract and demanding that Centennial indemnify LPP against all losses, damages, claims, costs, charges and expenses arising from CEM's alleged failures. In December 2009, LPP submitted a demand for arbitration of its dispute with CEM to the American Arbitration Association. The demand sought compensatory damages of $149.7 million. In June 2010, CEM and Bicent made a demand on Centennial Resources for indemnification under the 2007 purchase and sale agreement for indemnifiable losses, including defense fees and costs arising from LPP's arbitration demand and related to Centennial Resources' ownership of CEM prior to its sale to Bicent. Centennial and Centennial Resources filed a complaint with the Supreme Court of the State of New York in November 2010, against Bicent seeking damages for breach of contract and other relief including specific performance of the 2007 purchase and sale agreement allowing for Centennial Resources' participation in the arbitration proceeding and replacement of the letter of credit. On September 19, 2011, Bicent filed a counterclaim seeking damages against Centennial Resources related to Bicent's costs of defending the LPP arbitration demand which Bicent alleged were in excess of $14.0 million. The arbitration hearing on LPP's claim was held in the third quarter of 2011, and an arbitration award was issued January 13, 2012, awarding LPP $22.0 million. Centennial subsequently received a demand from LPP for payment of the arbitration award plus interest and attorneys' fees. An accrual related to the guarantee as a result of the arbitration award is recorded in discontinued operations on the Consolidated Statement of Income. The Company intends to vigorously defend against the claims of LPP and Bicent.

Construction Materials In 2009, LTM provided pavement work under a subcontract for reconstruction at the Klamath Falls Airport owned by the City of Klamath Falls, Oregon. In October 2010, the City of Klamath Falls filed a complaint in Oregon Circuit Court against the project's general contractor alleging the work performed by LTM is defective. The general contractor tendered the defense and indemnity of the claim to LTM and its insurance carrier. On January 18, 2011, the general contractor served a third party complaint against LTM seeking indemnity and contribution for damages imposed on the general contractor. LTM filed a fourth-party complaint seeking contribution and indemnity for damages imposed on LTM against the project engineer firm which prepared the specifications for the airport runway. LTM's insurance carrier accepted defense of the complaint against the general contractor and the third party complaint against LTM subject to reservation of its rights under the applicable insurance policy. Damages, including removal and replacement of the paved runway, were estimated by the plaintiff in its complaint as $6.0 million to $11.0 million. The Oregon Circuit Court granted a motion by LTM to dismiss certain of the plaintiff's claims relating to approximately $5.0 million of damages but allowed the plaintiff to amend its complaint. In its amended complaint, the plaintiff asserted new claims with estimated damages of $21.9 million plus interest and attorney fees. LTM and its insurers have been engaged in mediation and settlement discussions with the other parties to resolve this matter.

Until the fall of 2011 when it discontinued active mining operations at the pit, JTL operated the Target Range Gravel Pit in Missoula County, Montana under a 1975 reclamation contract pursuant to the Montana Opencut Mining Act. In September 2009, the Montana DEQ sent a letter asserting JTL was in violation of the Montana Opencut Mining Act by conducting mining operations outside a permitted area. JTL filed a complaint in Montana First Judicial District Court in June 2010, seeking a declaratory order that the reclamation contract is a valid permit under the Montana Opencut Mining Act. The Montana DEQ filed an answer and counterclaim to the complaint in August 2011, alleging JTL was in violation of the Montana Opencut Mining Act and requesting imposition of penalties of not more than $3.7 million plus not more than $5,000 per day from the date of the counterclaim. The Company believes the operation of the Target Range Gravel Pit was conducted under a valid permit; however, the imposition of civil penalties is reasonably possible. The Company intends to resolve this matter through settlement or continuation of the Montana First Judicial District Court litigation.

Natural Gas Gathering Operations In January 2010, SourceGas filed an application with the Colorado State District Court to compel Bitter Creek to arbitrate a dispute regarding operating pressures under a natural gas gathering contract on one of Bitter Creek's pipeline gathering systems in Montana. Bitter Creek resisted the application and sought a declaratory order interpreting the gathering contract. In May 2010, the Colorado State District Court granted the application and ordered Bitter Creek into arbitration. An arbitration hearing was held in August 2010. In October 2010, Bitter Creek was notified that the arbitration panel issued an award in favor of SourceGas for approximately $26.6 million. As a result, Bitter Creek, which is included in the pipeline and energy services segment, recorded a $26.6 million charge ($16.5 million after tax) in the third quarter of 2010, which is recorded in operation and maintenance expense on the Consolidated Statement of Income. On April 20, 2011, the Colorado State District Court entered an order denying a motion by Bitter Creek to vacate the arbitration award and granting a motion by SourceGas to confirm the arbitration award as a court judgment. The Colorado State District Court also awarded $293,000 to SourceGas for legal fees and expenses. Bitter Creek filed an appeal from the Colorado State District Court's order and judgment to the Colorado Court of Appeals on April 28, 2011.

In a related matter, Omimex filed a complaint against Bitter Creek in Montana Seventeenth Judicial District Court in July 2010 alleging Bitter Creek breached a separate gathering contract with Omimex as a result of the increased operating pressures demanded by SourceGas on the same natural gas gathering system. In December 2011, Omimex filed an amended complaint alleging Bitter Creek breached obligations to operate its gathering system as a common carrier under United States and Montana law. Bitter Creek removed the action to the United States District Court for the District of Montana. Expert reports submitted by Omimex contend its damages as a result of the increased operating pressures are $18.8 million to $22.6 million. The Company believes the claims asserted by Omimex are without merit and intends to vigorously defend against the claims.

The Company also is involved in other legal actions in the ordinary course of its business. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above and other legal proceedings will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters
Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $70 million. It is not possible to estimate the cost of a corrective action plan until the remedial investigation and feasibility study have been completed, the EPA has decided on a strategy and a ROD has been published. Corrective action will be taken after the development of a proposed plan and ROD on the harbor site is issued. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

Based upon a review of the Portland Harbor sediment contamination evaluation by the Oregon DEQ and other information available, Knife River - Northwest does not believe it is a Responsible Party. In addition, Knife River -

Northwest has notified Georgia-Pacific West, Inc., that it intends to seek indemnity for liabilities incurred in relation to the above matters pursuant to the terms of their sale agreement. Knife River - Northwest has entered into an agreement tolling the statute of limitations in connection with the LWG's potential claim for contribution to the costs of the remedial investigation and feasibility study. By letter in March 2009, LWG stated its intent to file suit against Knife River - Northwest and others to recover LWG's investigation costs to the extent Knife River - Northwest cannot demonstrate its non-liability for the contamination or is unwilling to participate in an alternative dispute resolution process that has been established to address the matter. At this time, Knife River - Northwest has agreed to participate in the alternative dispute resolution process.

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

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

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million. The Oregon DEQ is preparing a staff report which will recommend a cleanup alternative for the site. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has reserved $1.2 million for remediation of this site.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million. Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington Department of Ecology issued notice it considered Cascade a PRP for hazardous substances at the site. In September 2011, the EPA issued notice of a proposal to add the site to the National Priorities List. Cascade has met with the EPA to discuss a possible settlement agreement and administrative order for performance of a remedial investigation and feasibility study of the site with the intent of reaching consensus on the scope and schedule for the remedial investigation and feasibility study. Cascade has reserved $6.4 million for remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site until the next general rate case. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

The third claim is for contamination at a site in Bellingham, Washington. Cascade received notice from a party in May 2008 that Cascade may be a PRP, along with other parties, for contamination from a manufactured gas plant owned by Cascade and its predecessor from about 1946 to 1962. The notice indicates that current estimates to complete investigation and cleanup of the site exceed $8.0 million. Other PRPs have reached an agreed order and work plan with the Washington Department of Ecology for completion of a remedial investigation and feasibility study for the site. A report documenting the initial phase of the remedial investigation was completed in June 2011. There is currently not enough information available to estimate the potential liability to Cascade associated with this claim although Cascade believes its proportional share of any liability will be relatively small in comparison to other PRPs. The plant manufactured gas from coal between approximately 1890 and 1946. In 1946, shortly after Cascade's predecessor acquired the plant, it converted the plant to a propane-air gas facility. There are no documented wastes or by-products resulting from the mixing or distribution of propane-air gas.

Cascade has received notices from certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2011, were $27.8 million in 2012, $24.3 million in 2013, $16.4 million in 2014, $8.6 million in 2015, $5.8 million in 2016 and $35.9 million thereafter. Rent expense was $40.7 million, $38.7 million and $43.4 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Purchase commitments

The Company has entered into various commitments, largely natural gas and coal supply, purchased power, natural gas transportation and storage, service and construction materials supply contracts. These commitments range from one to 49 years. The commitments under these contracts as of December 31, 2011, were $478.0 million in 2012, $215.9 million in 2013, $135.8 million in 2014, $71.1 million in 2015, $36.7 million in 2016 and $287.0 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2011, 2010 and 2009, were $626.3 million, $611.7 million and $723.1 million.

Guarantees

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

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

WBI Holdings has guaranteed certain of Fidelity's natural gas and oil swap and collar agreement obligations. There is no fixed maximum amount guaranteed in relation to the natural gas and oil swap and collar agreements as the amount of the obligation is dependent upon natural gas and oil commodity prices. The amount of hedging activity entered into by the subsidiary is limited by corporate policy. The guarantees of the natural gas and oil swap and collar agreements at December 31, 2011, expire in the years ranging from 2012 to 2013; however, Fidelity continues to enter into additional hedging activities and, as a result, WBI Holdings from time to time may issue additional guarantees on these hedging obligations. The amount outstanding by Fidelity was $4.3 million and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event Fidelity defaults under its obligations, WBI Holdings would be required to make payments under its guarantees.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, natural gas transportation and sales agreements, gathering contracts and certain other guarantees. At December 31, 2011, the fixed maximum amounts guaranteed under these agreements aggregated $85.6 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $42.0 million in 2012; $34.4 million in 2013; $1.3 million in 2014; $100,000 in 2015; $100,000 in 2016; $800,000 in 2018; $300,000 in 2019; $2.6 million, which is subject to expiration on a specified number of days after the receipt of written notice; and $4.0 million, which has no scheduled maturity date. The amount outstanding by subsidiaries of the Company under the above guarantees was $500,000 and was reflected on the Consolidated Balance Sheet at December 31, 2011. In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies, natural gas transportation agreements and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2011, the fixed maximum amounts guaranteed under these letters of credit, aggregated $27.4 million. In 2012 and 2013, $24.1 million and $3.3 million, respectively, of letters of credit are scheduled to expire. There were no amounts outstanding under the above letters of credit at December 31, 2011.

WBI Holdings has an outstanding guarantee to Williston Basin. This guarantee is related to a natural gas transportation and storage agreement that guarantees the performance of Prairielands. At December 31, 2011, the fixed maximum amount guaranteed under this agreement was $5.0 million and is scheduled to expire in 2014. In the event of Prairielands' default in its payment obligations, WBI Holdings would be required to make payment under its guarantee. The amount outstanding by Prairielands under the above guarantee was $1.2 million. The amount outstanding under this guarantee was not reflected on the Consolidated Balance Sheet at December 31, 2011, because this intercompany transaction was eliminated in consolidation.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2011.

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries, as well as an arbitration award. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2011, approximately $463 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Supplementary Financial Information
Quarterly Data (Unaudited)
The following unaudited information shows selected items by quarter for the years 2011 and 2010:

	First Quarter	Second Quarter	Third Quarter *	Fourth Quarter **
	(In thousands, except per share amounts)			
2011				
Operating revenues	$901,805	$930,757	$1,152,181	$1,065,749
Operating expenses	823,739	848,454	1,032,760	939,172
Operating income	78,066	82,303	119,421	126,577
Income from continuing operations	42,529	45,235	64,100	74,088
Income (loss) from discontinued operations, net of tax	448	(168)	(126)	(13,080)
Net income	42,977	45,067	63,974	61,008
Earnings per common share - basic:				
Earnings before discontinued operations	.22	.24	.34	.39
Discontinued operations, net of tax	.01	—	—	(.07)
Earnings per common share - basic	.23	.24	.34	.32
Earnings per common share - diluted:				
Earnings before discontinued operations	.22	.24	.34	.39
Discontinued operations, net of tax	.01	—	—	(.07)
Earnings per common share - diluted	.23	.24	.34	.32
Weighted average common shares outstanding:				
Basic	188,671	188,794	188,794	188,794
Diluted	188,815	188,968	188,797	188,932
2010				
Operating revenues	$834,777	$906,444	$1,125,923	$1,042,551
Operating expenses	751,848	817,782	1,016,961	912,377
Operating income	82,929	88,662	108,962	130,174
Income from continuing operations	41,772	48,938	61,010	92,300
Loss from discontinued operations, net of tax	—	—	—	(3,361)
Net income	41,772	48,938	61,010	88,939
Earnings per common share - basic:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share - basic	.22	.26	.32	.47
Earnings per common share - diluted:				
Earnings before discontinued operations	.22	.26	.32	.49
Discontinued operations, net of tax	—	—	—	(.02)
Earnings per common share - diluted	.22	.26	.32	.47
Weighted average common shares outstanding:				
Basic	187,963	188,129	188,170	188,281
Diluted	188,220	188,267	188,338	188,374

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

** 2011 reflects an arbitration charge of $13.0 million (after tax) related to a guarantee of a construction contract. For more information, see Note 19. 2010 reflects a $13.8 million (after tax) gain on the sale of the Brazilian Transmission Lines. For more information, see Note 4.

Certain Company operations are highly seasonal and revenues from and certain expenses for such operations may fluctuate significantly among quarterly periods. Accordingly, quarterly financial information may not be indicative of results for a full year.

Exploration and Production Activities (Unaudited)
Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties with potential development opportunities, exploratory drilling and the

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

The information that follows includes Fidelity's proportionate share of all its natural gas and oil interests.

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

	2011	2010	2009
	(In thousands)		
Subject to amortization	$2,345,114	$2,138,565	$1,815,380
Not subject to amortization	232,462	182,402	178,214
Total capitalized costs	2,577,576	2,320,967	1,993,594
Less accumulated depreciation, depletion and amortization	1,229,654	1,093,723	969,630
Net capitalized costs	$1,347,922	$1,227,244	$1,023,964

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

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

Years ended December 31,	2011 *	2010 *	2009 *
	(In thousands)		
Acquisitions:			
Proved properties	$3,999	$89,733	$3,879
Unproved properties	63,354	92,100	8,771
Exploration	41,775	33,226	33,123
Development	161,647	139,733	135,202
Total capital expenditures	$270,775	$354,792	$180,975

* Excludes net additions/(reductions) to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of natural gas and oil wells, as discussed in Note 10, of $(1.8) million, $11.1 million and $2.0 million for the years ended December 31, 2011, 2010 and 2009, respectively.

The following summary reflects income resulting from the Company's operations of natural gas and oil producing activities, excluding corporate overhead and financing costs:

Years ended December 31,	2011	2010	2009
	(In thousands)		
Revenues:			
Sales to affiliates	$93,713	$115,784	$101,230
Sales to external customers	359,873	318,565	338,425
Production costs	140,606	127,403	123,148
Depreciation, depletion and amortization*	139,539	127,266	126,278
Write-down of natural gas and oil properties	—	—	620,000
Pretax income	173,441	179,680	(429,771)

Income tax expense	63,655	66,293	(164,216)
Results of operations for producing activities	$109,786	$113,387	$(265,555)

* Includes accretion of discount for asset retirement obligations of $3.6 million, $3.2 million and $2.7 million for the years ended December 31, 2011, 2010 and 2009, respectively, as discussed in Note 10.

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The reserve estimates as of December 31, 2011, 2010 and 2009, were calculated using SEC Defined Prices and prior to that time, reserve estimates were calculated using spot market prices that existed at the end of the applicable period. Other factors used in the reserve estimates are current estimates of well operating and future development costs, taxes, timing of operations, and the interests owned by the Company in the properties. These estimates are refined as new information becomes available.

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

Estimates of economically recoverable natural gas and oil reserves and future net revenues therefrom are based upon a number of variable factors and assumptions. For these reasons, estimates of economically recoverable reserves and future net revenues may vary from actual results.

The Company's interests in natural gas and oil reserves are located in the United States and in and around the Gulf of Mexico.

The changes in the Company's estimated quantities of proved natural gas and oil reserves for the year ended December 31, 2011, were as follows:

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	448,397	32,867	645,596
Production	(45,598)	(3,500)	(66,596)
Extensions and discoveries	28,221	6,138	65,049
Improved recovery	—	—	—
Purchases of proved reserves	54	239	1,486
Sales of proved reserves	—	—	—
Revisions of previous estimates	(51,247)	(1,397)	(59,627)
Balance at end of year	379,827	34,347	585,908

Significant changes in proved reserves for the year ended December 31, 2011, include:

- Extensions and discoveries of 65.0 Bcfe primarily due to drilling activity at the Company's Bakken and Big Horn properties
- Revisions of previous estimates of (59.6) Bcfe, largely the result of a reduction in PUD reserves of 53.6 Bcfe resulting principally in the Company's Bowdoin, Baker, Coalbed, East Texas and Big Horn Basin properties. The remaining negative revisions were a reduction in PDP natural gas reserves.

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

	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)
Proved developed and undeveloped reserves:			
Balance at beginning of year	448,425	34,216	653,724
Production	(50,391)	(3,262)	(69,963)
Extensions and discoveries	36,191	3,389	56,523
Improved recovery	—	—	—
Purchases of proved reserves	55,119	979	60,991

Sales of proved reserves	(92)	(18)	(202)
Revisions of previous estimates	(40,855)	(2,437)	(55,477)
Balance at end of year	448,397	32,867	645,596

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

- Extensions and discoveries of 56.5 Bcfe primarily due to drilling activity at the Company's Bakken, Baker, Bowdoin and east Texas properties

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

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

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

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

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

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

	2011	2010	2009
Proved developed reserves:			
Natural Gas (MMcf)	303,495	334,911	321,561
Oil (MBbls)	28,878	26,586	26,794
Total (MMcfe)	476,763	494,426	482,329
PUD reserves:			
Natural Gas (MMcf)	76,332	113,486	126,864
Oil (MBbls)	5,469	6,281	7,422
Total (MMcfe)	109,145	151,170	171,395
Total proved reserves:			
Natural Gas (MMcf)	379,827	448,397	448,425
Oil (MBbls)	34,347	32,867	34,216
Total (MMcfe)	585,908	645,596	653,724

As of December 31, 2011, the Company had 109.1 Bcfe of PUD reserves, which is a decrease of 42.0 Bcfe from December 31, 2010. The decrease relates to the Company converting 27.1 Bcfe of its December 31, 2010, PUD reserves into proved developed reserves in 2011, requiring $62.9 million of drilling and completion capital and 53.6

Bcfe of negative revisions applied to PUD locations primarily in the Company's natural gas properties. These changes were partially offset by 38.7 Bcfe of new PUD reserves primarily in the Company's oil properties. At December 31, 2011, the Company did not have any PUD locations that remained undeveloped for five years or more. Future development costs estimated to be spent in each of the next three years to develop PUD reserves as of December 31, 2011, are \$109.3 million in 2012, \$47.8 million in 2013 and \$13.7 million in 2014.

The standardized measure of the Company's estimated discounted future net cash flows of total proved reserves associated with its various natural gas and oil interests at December 31 was as follows:

	2011	2010	2009
	(In thousands)		
Future cash inflows	$4,188,000	$3,790,700	$2,991,200
Future production costs	1,560,300	1,393,000	1,095,600
Future development costs	285,300	312,500	315,000
Future net cash flows before income taxes	2,342,400	2,085,200	1,580,600
Future income tax expense	531,100	432,800	291,000
Future net cash flows	1,811,300	1,652,400	1,289,600
10% annual discount for estimated timing of cash flows	832,500	756,300	630,800
Discounted future net cash flows relating to proved natural gas and oil reserves	$978,800	$896,100	$658,800

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

	2011	2010	2009
	(In thousands)		
Beginning of year	$896,100	$658,800	$969,800
Net revenues from production	(301,500)	(270,000)	(200,900)
Net change in sales prices and production costs related to future production	82,300	362,400	(364,800)
Extensions and discoveries, net of future production-related costs	226,300	130,500	70,500
Improved recovery, net of future production-related costs	—	—	—
Purchases of proved reserves, net of future production-related costs	9,500	99,800	—
Sales of proved reserves	—	(500)	(1,100)
Changes in estimated future development costs	51,100	34,100	43,600
Development costs incurred during the current year	56,300	43,100	46,400
Accretion of discount	105,000	76,500	115,900
Net change in income taxes	(55,800)	(103,300)	142,800
Revisions of previous estimates	(92,900)	(132,000)	(155,500)
Other	2,400	(3,300)	(7,900)
Net change	82,700	237,300	(311,000)
End of year	$978,800	$896,100	$658,800

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

The standardized measure of discounted future net cash flows does not purport to represent the fair market value of natural gas and oil properties. There are significant uncertainties inherent in estimating quantities of proved reserves and in projecting rates of production and the timing and amount of future costs. In addition, future realization of natural gas and oil prices over the remaining reserve lives may vary significantly from SEC Defined Prices.

Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

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

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. The Company's disclosure controls and other procedures are designed to provide reasonable assurance that information required to be disclosed in the reports that the Company files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. The Company's disclosure controls and procedures include controls and procedures designed to provide reasonable assurance that information required to be disclosed is accumulated and communicated to management, including the Company's chief executive officer and chief financial officer, to allow timely decisions regarding required disclosure. The Company's management, with the participation of the Company's chief executive officer and chief financial officer, has evaluated the effectiveness of the Company's disclosure controls and procedures. Based upon that evaluation, the chief executive officer and the chief financial officer have concluded that, as of the end of the period covered by this report, such controls and procedures were effective at a reasonable assurance level.

Changes in Internal Controls

No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2011, that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The information required by this item is included in this Form 10-K at Item 8 - Management's Report on Internal Control Over Financial Reporting.

Attestation Report of the Registered Public Accounting Firm

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

Part III

Item 10. Directors, Executive Officers and Corporate Governance

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

Item 11. Executive Compensation

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

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity Compensation Plan Information
The following table includes information as of December 31, 2011, with respect to the Company's equity compensation plans:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights		(b) Weighted average exercise price of outstanding options, warrants and rights	(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
Equity compensation plans approved by stockholders (1)	768,904	(2)	$19.30	6,310,260	(3)(4)
Equity compensation plans not approved by stockholders	N/A		N/A	N/A	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan, the Long-Term Performance-Based Incentive Plan and the Non-Employee Director Stock Compensation Plan.
(2) Includes 762,154 performance shares.
(3) In addition to being available for issuance upon exercise of options, 357,757 shares remain available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan in connection with grants of stock appreciation rights, restricted stock, performance units, performance shares or other equity-based awards. 5,686,144 shares under the Long-Term Performance-Based Incentive Plan remain available for future issuance in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.
(4) This amount also includes 266,359 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded shares equal in value to $110,000 annually. A non-employee director may acquire additional shares under the plan in lieu of receiving the cash portion of the director's retainer or fees.

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

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

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

Item 14. Principal Accountant Fees and Services

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

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

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

Condensed Statements of Income

Years ended December 31,	2011	2010	2009
	(In thousands)		
Operating revenues	$518,268	$503,658	$514,519
Operating expenses	450,579	431,293	458,130
Operating income	67,689	72,365	56,389
Other income	2,710	5,734	6,588
Interest expense	18,660	16,664	13,996
Income before income taxes	51,739	61,435	48,981
Income taxes	10,476	17,983	13,279
Equity in earnings of subsidiaries	171,763	197,207	(158,976)
Net income	213,026	240,659	(123,274)
Dividends declared on preferred stocks	685	685	685
Earnings on common stock	$212,341	$239,974	$(123,959)

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

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

December 31,	2011	2010
(In thousands, except shares and per share amounts)		
Assets		
Current assets:		
Cash and cash equivalents	$6,900	$6,275
Receivables, net	67,761	76,757
Accounts receivable from subsidiaries	28,734	27,837
Inventories	42,596	34,583
Deferred income taxes	2	—
Prepayments and other current assets	12,154	15,473
Total current assets	158,147	160,925
Investments	47,835	48,038
Investment in subsidiaries	2,402,891	2,336,133
Property, plant and equipment	1,453,089	1,388,128
Less accumulated depreciation, depletion and amortization	605,510	583,447
Net property, plant and equipment	847,579	804,681
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	166,732	119,081
Total deferred charges and other assets	171,544	123,893
Total assets	$3,627,996	$3,473,670
Liabilities and Stockholders' Equity		
Current liabilities:		
Short-term borrowings	$—	$20,000
Long-term debt due within one year	107	107
Accounts payable	37,986	36,235
Accounts payable to subsidiaries	4,868	9,445
Taxes payable	18,304	8,104
Deferred income taxes	—	469
Dividends payable	31,794	30,773
Accrued compensation	10,173	11,540
Other accrued liabilities	27,064	26,002
Total current liabilities	130,296	142,675
Long-term debt	280,781	280,889
Deferred credits and other liabilities:		
Deferred income taxes	137,751	103,725
Other liabilities	303,601	253,579
Total deferred credits and other liabilities	441,352	357,304
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	15,000	15,000
Common stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 188,332,485 shares in 2011 and 188,901,379 shares in 2010	189,332	188,901

Other paid-in capital	1,035,739	1,026,349
Retained earnings	1,586,123	1,497,439
Accumulated other comprehensive loss	(47,001)	(31,261)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,760,567	2,677,802
Total stockholders' equity	2,775,567	2,692,802
Total liabilities and stockholders' equity	$3,627,996	$3,473,670

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

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

Years ended December 31,	2011	2010	2009
	(In thousands)		
Net cash provided by operating activities	$217,514	$185,887	$209,128
Investing activities:			
Capital expenditures	(74,580)	(114,045)	(120,352)
Net proceeds from sale or disposition of property and other	720	625	1,039
Investments in and advances to subsidiaries	(5,701)	(1,636)	—
Investments from and advances from subsidiaries	—	—	2,916
Disposition of investments in subsidiaries	—	—	20,000
Investments	—	(742)	(637)
Net cash used in investing activities	(79,561)	(115,798)	(97,034)
Financing activities:			
Issuance of short-term borrowings	—	20,000	—
Repayment of short-term borrowings	(20,000)	—	—
Issuance of long-term debt	—	—	50,000
Repayment of long-term debt	(107)	(107)	(85,104)
Proceeds from issuance of common stock	5,744	4,972	65,207
Dividends paid	(123,323)	(119,157)	(115,023)
Tax benefit on stock-based compensation	358	375	264
Net cash used in financing activities	(137,328)	(93,917)	(84,656)
Increase (decrease) in cash and cash equivalents	625	(23,828)	27,438
Cash and cash equivalents - beginning of year	6,275	30,103	2,665
Cash and cash equivalents - end of year	$6,900	$6,275	$30,103

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

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

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

Note 2 - Debt The Company has long-term debt obligations outstanding of $280.9 million at December 31, 2011, with annual maturities of $100,000 from 2012 to 2015, $50.0 million in 2016 and $230.5 million scheduled to mature in years after 2016.

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

Note 3 - Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $96.1 million, $96.4 million and $116.3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

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

For the years ended December 31, 2011, 2010 and 2009

Description	Balance at Beginning of Year (In thousands)	Additions Charged to Costs and Expenses	Other *	Deductions **	Balance at End of Year
Allowance for doubtful accounts:					
2011	$15,284	$3,977	$2,112	$8,966	$12,407
2010	16,649	5,044	2,300	8,709	15,284
2009	13,691	12,152	1,412	10,606	16,649

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

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

3. Exhibits

3(a)	Restated Certificate of Incorporation of the Company, as amended, dated May 13, 2010, filed as Exhibit 3(a) to Form 10-Q for the quarter ended September 30, 2010, filed on November 3, 2010, in File No. 1-3480*
3(b)	Company Bylaws, as amended and restated, on November 17, 2011**
4(a)	Indenture, dated as of December 15, 2003, between the Company and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*
4(b)	First Supplemental Indenture, dated as of November 17, 2009, between the Company and The Bank of New York Mellon, as trustee, filed as Exhibit 4(c) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
4(c)	Centennial Energy Holdings, Inc. Master Shelf Agreement, dated April 29, 2005, among Centennial Energy Holdings, Inc. and the Prudential Insurance Company of America, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2005, filed on August 3, 2005, in File No. 1-3480*
4(d)	Letter Amendment No. 1 to Amended and Restated Master Shelf Agreement, dated May 17, 2006, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2006, filed on August 4, 2006, in File No. 1-3480*
4(e)	MDU Resources Group, Inc. Credit Agreement, dated May 26, 2011, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent**
4(f)	Centennial Energy Holdings, Inc. Credit Agreement, dated December 13, 2007, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4(j) to Form 10-K for the year ended December 31, 2007, filed on February 20, 2008, in File No. 1-3480*
4(g)	Consent dated November 9, 2009, under Centennial Energy Holdings, Inc. Credit Agreement, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Other Financial Institutions party thereto, filed as Exhibit 4(i) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
4(h)	MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC and the Prudential Insurance Company of America, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*
4(i)	Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder, filed as Exhibit 4(b) to Form 10-Q for the quarter ended September 30, 2008, filed on November 5, 2008, in File No. 1-3480*
4(j)	Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K dated August 12, 1992, in File No. 1-7196*

4(k)	First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*
4(l)	Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*
4(m)	Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*
+10(a)	Supplemental Income Security Plan, as amended and restated November 12, 2009, filed as Exhibit 10(b) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*

+10(b)	Directors' Compensation Policy, as amended May 12, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*
+10(c)	Deferred Compensation Plan for Directors, as amended May 15, 2008, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*
+10(d)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*
+10(e)	Non-Employee Director Long-Term Incentive Compensation Plan, as amended November 12, 2009, filed as Exhibit 10(f) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
+10(f)	WBI Holdings, Inc. Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(i) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
+10(g)	Knife River Corporation Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended November 16, 2009, filed as Exhibit 10(j) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
+10(h)	Long-Term Performance-Based Incentive Plan, as amended November 17, 2011**
+10(i)	MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended November 15, 2007, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(l) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
+10(j)	Montana-Dakota Utilities Co. Executive Incentive Compensation Plan, as amended November 15, 2007, and Rules and Regulations, as amended November 11, 2009, filed as Exhibit 10(m) to Form 10-K for the year ended December 31, 2009, filed on February 17, 2010, in File No. 1-3480*
+10(k)	Form of Change of Control Employment Agreement, as amended May 15, 2008, filed as Exhibit 10.1 to Form 8-K dated May 15, 2008, filed on May 20, 2008, in File No. 1-3480*
+10(l)	MDU Resources Group, Inc. Executive Officers with Change of Control Employment Agreements Chart, as of December 31, 2010, filed as Exhibit 10(n) to Form 10-K for the year ended December 31, 2010, filed on February 23, 2011, in File No. 1-3480*
+10(m)	Supplemental Executive Retirement Plan for John G. Harp, dated December 4, 2006, filed as Exhibit 10(ag) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*
+10(n)	Employment Letter for John G. Harp, dated July 20, 2005, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2006, filed on February 21, 2007, in File No. 1-3480*
+10(o)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 15, 2011, filed as Exhibit 10.4 to Form 8-K dated February 15, 2011, filed on February 22, 2011, in File No. 1-3480*
+10(p)	

	MDU Construction Services Group, Inc. Executive Incentive Compensation Plan, as amended January 31, 2008, and Rules and Regulations, as amended February 16, 2009, filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2009, filed on May 6, 2009, in File No. 1-3480*
+10(q)	Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan as amended February 22, 2011, filed as Exhibit 10.2 to Form 8-K dated February 15, 2011, filed on February 22, 2011, in File No. 1-3480*
+10(r)	Agreement for Termination of Change of Control Employment Agreement, dated June 15, 2010, by and between MDU Resources Group, Inc. and Terry D. Hildestad, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, in File No. 1-3480*

+10(s)	Form of Notice of Expiration of Coverage Period - Change of Control Employment Agreement, dated June 15, 2010, sent by MDU Resources Group, Inc. to William E. Schneider, John G. Harp, Steven L. Bietz, David L. Goodin, William R. Connors, Mark A. Del Vecchio, Nicole A. Kivisto, Cynthia J. Norland, Paul K. Sandness, Doran N. Schwartz, and John P. Stumpf, filed as Exhibit 10(c) to Form 10-Q for the quarter ended June 30, 2010, filed on August 6, 2010, in File No. 1-3480*
+10(t)	Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated August 12, 2010, filed on August 17, 2010, in File No. 1-3480*
+10(u)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of December 31, 2011**
+10(v)	Employment Letter for J. Kent Wells, dated March 9, 2011**
+10(w)	MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan 2011 Fidelity President and CEO Award Agreement**
+10(x)	MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as adopted November 17, 2011**
+10(y)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated March 1, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*
+10(z)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 29, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2011, filed on May 5, 2011, in File No. 1-3480*
+10(aa)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2011, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*
+10(ab)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*
+10(ac)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2011**
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**
21	Subsidiaries of MDU Resources Group, Inc.**
23(a)	Consent of Independent Registered Public Accounting Firm**
23(b)	Consent of Ryder Scott Company, L.P.**
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**

32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
95	Mine Safety Disclosures**
99	Ryder Scott Company, L.P. report dated January 10, 2012**
101	The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2011, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Balance Sheets, (iii) the Consolidated Statements of Common Stockholders' Equity, (iv) the Consolidated Statements of Cash Flows, (v) the Notes to Consolidated Financial Statements, tagged in summary and detail, (vi) Schedule I - Condensed Financial Information of Registrant, tagged in summary and detail and (vii) Schedule II - Consolidated Valuation and Qualifying Accounts, tagged in summary and detail

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

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

Signatures

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

MDU Resources Group, Inc.

Date:	February 24, 2012	By:	/s/ Terry D. Hildestad Terry D. Hildestad (President and Chief Executive Officer)

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

Signature	Title	Date
/s/ Terry D. Hildestad Terry D. Hildestad (President and Chief Executive Officer)	Chief Executive Officer and Director	February 24, 2012
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 24, 2012
/s/ Nicole A. Kivisto Nicole A. Kivisto (Vice President, Controller and Chief Accounting Officer)	Chief Accounting Officer	February 24, 2012
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 24, 2012
/s/ Thomas Everist Thomas Everist	Director	February 24, 2012
/s/ Karen B. Fagg Karen B. Fagg	Director	February 24, 2012
/s/ A. Bart Holaday A. Bart Holaday	Director	February 24, 2012
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 24, 2012
/s/ Thomas C. Knudson Thomas C. Knudson	Director	February 24, 2012
/s/ Richard H. Lewis Richard H. Lewis	Director	February 24, 2012

/s/ Patricia L. Moss Patricia L. Moss	Director	February 24, 2012
/s/ John K. Wilson John K. Wilson	Director	February 24, 2012