MDU RESOURCES GROUP INC
Form 10-K
February 17, 2010

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

FORM 10-K

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

For the fiscal year ended December 31, 2009

OR

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

For the transition period from _____________ to ______________

Commission file number 1-3480

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

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

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

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

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $1.00	New York Stock Exchange

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

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

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o.

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

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

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

(Do not check if a smaller reporting company)

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2009: $3,489,895,496.

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 2, 2010: 187,863,394 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Portions of the registrant's 2010 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
ALJ	Administrative Law Judge
Alusa	Tecnica de Engenharia Electrica - Alusa
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
Bbl	Barrel
Bcf	Billion cubic feet
BER	Montana Board of Environmental Review
Big Stone Station	450-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Big Stone Station II	Formerly proposed coal-fired electric generating facility near Big Stone City, South Dakota (the Company had anticipated ownership of at least 116 MW)
Bitter Creek	Bitter Creek Pipelines, LLC, an indirect wholly owned subsidiary of WBI Holdings
Black Hills Power	Black Hills Power and Light Company
Brazilian Transmission Lines	Company's equity method investment in companies owning ECTE, ENTE and ERTE
Btu	British thermal unit
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CBNG	Coalbed natural gas
CELESC	Centrais Elétricas de Santa Catarina S.A.
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
CEMIG	Companhia Energética de Minas Gerais
Centennial	Centennial Energy Holdings, Inc., a direct wholly owned subsidiary of the Company
Centennial Capital	Centennial Holdings Capital LLC, a direct wholly owned subsidiary of Centennial
Centennial International	Centennial Energy Resources International, Inc., a direct wholly owned subsidiary of Centennial Resources
Centennial Power	Centennial Power, Inc., a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
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

Company	MDU Resources Group, Inc.
D.C. Appeals Court	U.S. Court of Appeals for the District of Columbia Circuit
dk	Decatherm

ECTE	Empresa Catarinense de Transmissão de Energia S.A.
EIS	Environmental Impact Statement
ENTE	Empresa Norte de Transmissão de Energia S.A.
EPA	U.S. Environmental Protection Agency
ERTE	Empresa Regional de Transmissão de Energia S.A.
ESA	Endangered Species Act
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings
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
Hartwell	Hartwell Energy Limited Partnership, a former equity method investment of the Company (sold in the third quarter of 2007)
IBEW	International Brotherhood of Electrical Workers
ICWU	International Chemical Workers Union
Indenture	Indenture dated as of December 15, 2003, as supplemented, from the Company to The Bank of New York as Trustee
Innovatum	Innovatum, Inc., a former indirect wholly owned subsidiary of WBI Holdings (the stock and Innovatum's assets have been sold)
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital (acquired October 1, 2008)
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
Kennecott	Kennecott Coal Sales Company
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LTM	LTM, Inc., an indirect wholly owned subsidiary of Knife River
LPP	Lea Power Partners, LLC, a former indirect wholly owned subsidiary of Centennial Resources (member interests were sold in October 2006)
LWG	Lower Willamette Group
MAPP	Mid-Continent Area Power Pool
MBbls	Thousands of barrels
MBI	Morse Bros., Inc., an indirect wholly owned subsidiary of Knife River
MBOGC	Montana Board of Oil and Gas Conservation
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations

Mdk	Thousand decatherms
MDU Brasil	MDU Brasil Ltda., an indirect wholly owned subsidiary of Centennial International

MDU Construction Services	MDU Construction Services Group, Inc., a direct wholly owned subsidiary of Centennial
MDU Energy Capital	MDU Energy Capital, LLC, a direct wholly owned subsidiary of the Company
MEIC	Montana Environmental Information Center, Inc.
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 State Department of Environmental Quality
Montana First Judicial District Court	Montana First Judicial District Court, Lewis and Clark County
Montana Twenty-Second Judicial District Court	Montana Twenty-Second Judicial District Court, Big Horn County
Mortgage	Indenture of Mortgage dated May 1, 1939, as supplemented, amended and restated, from the Company to The Bank of New York and Douglas J. MacInnes, successor trustees
MPX	MPX Termoceara Ltda. (49 percent ownership, sold in June 2005)
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NEPA	National Environmental Policy Act
North Dakota District Court	North Dakota South Central Judicial District Court for Burleigh County
NPRC	Northern Plains Resource Council
NSPS	New Source Performance Standards
Oil	Includes crude oil, condensate and natural gas liquids
OPUC	Oregon Public Utilities Commission
Order on Rehearing	Order on Rehearing and Compliance and Remanding Certain Issues for Hearing
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
Prairielands	Prairielands Energy Marketing, Inc., an indirect wholly owned subsidiary of WBI Holdings
PRP	Potentially Responsible Party
Proxy Statement	Company's 2010 Proxy Statement
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
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
South Dakota Federal District Court	U.S. District Court for the District of South Dakota
South Dakota SIP	South Dakota State Implementation Plan
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan
TRWUA	Tongue River Water Users' Association
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
WYPSC	Wyoming Public Service Commission

Part I

Forward-Looking Statements

This Form 10-K contains forward-looking statements within the meaning of Section 21E of the Exchange Act. Forward-looking statements are all statements other than statements of historical fact, including without limitation those statements that are identified by the words "anticipates," "estimates," "expects," "intends," "plans," "predicts" and similar expressions, and include statements concerning plans, objectives, goals, strategies, future events or performance, and underlying assumptions (many of which are based, in turn, upon further assumptions) and other statements that are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature, including statements contained within Item 7 – MD&A – Prospective Information.

Forward-looking statements involve risks and uncertainties, which could cause actual results or outcomes to differ materially from those expressed. The Company's expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including without limitation, management's examination of historical operating trends, data contained in the Company's records and other data available from third parties. Nonetheless, the Company's expectations, beliefs or projections may not be achieved or accomplished.

Any forward-looking statement contained in this document speaks only as of the date on which the statement is made, and the Company undertakes no obligation to update any forward-looking statement or statements to reflect events or circumstances that occur after the date on which the statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of the factors, nor can it assess the effect of each factor on the Company's business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. All forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are expressly qualified by the risk factors and cautionary statements in this Form 10-K, including statements contained within Item 1A – Risk Factors.

Items 1 and 2. Business and Properties

General
The Company is a diversified natural resource company, which was incorporated under the laws of the state of Delaware in 1924. Its principal executive offices are at 1200 West Century Avenue, P.O. Box 5650, Bismarck, North Dakota 58506-5650, telephone (701) 530-1000.

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

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

The Company's equity method investment in the Brazilian Transmission Lines, as discussed in Item 8 – Note 4, is reflected in the Other category.

As of December 31, 2009, the Company had 8,081 employees with 158 employed at MDU Resources Group, Inc., 874 at Montana-Dakota, 31 at Great Plains, 329 at Cascade, 264 at Intermountain, 603 at WBI Holdings, 2,879 at Knife River and 2,943 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.

At Montana-Dakota and Williston Basin, 365 and 80 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through May 30, 2011, and March 31, 2011, for Montana-Dakota and Williston Basin, respectively.

At Cascade, 201 employees are represented by the ICWU. The labor contract with the field operations group, consisting of 169 employees, is effective through April 1, 2012. Cascade has an agreement with the bargaining unit consisting of 32 customer service representatives and credit and collections clerks in effect through March 19, 2011.

At Intermountain, 114 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2010.

Knife River has 43 labor contracts that represent approximately 440 of its construction materials employees. Knife River is in negotiations on five of its labor contracts.

MDU Construction Services has 126 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.

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 concern for reductions in GHG emissions and expansion of renewable energy resources has increased, the Company has placed an increasing emphasis on developing renewable generation resources. 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 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.

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 122,000 residential, commercial, industrial and municipal customers in 177 communities and adjacent rural areas as of December 31, 2009. The principal properties owned by Montana-Dakota for use in its electric operations include interests in nine 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. As of December 31, 2009, Montana-Dakota's net electric plant investment approximated $514.5 million.

The percentage of Montana-Dakota's 2009 retail electric utility operating revenues by jurisdiction is as follows: North Dakota – 58 percent; Montana – 24 percent; Wyoming – 11 percent; and South Dakota – 7 percent. Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters. Montana-Dakota participates in the Midwest ISO wholesale energy and ancillary services market. The Midwest ISO is a regional transmission organization responsible for operational control of the transmission systems of its members. The Midwest ISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets and an ancillary services market. As a member of Midwest ISO, Montana-Dakota's generation is sold into the Midwest ISO energy market and its energy needs are purchased from that market.

System Supply, System Demand and Competition Through an interconnected electric system, Montana-Dakota serves markets in portions of western North Dakota, including Bismarck, Dickinson and Williston; eastern Montana, including Glendive and Miles City; and northern South

Dakota, including Mobridge. The interconnected system consists of nine electric generating facilities, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 463,055 kW and a total summer net capability of 486,900 kW. Montana-Dakota's four principal generating stations are steam-turbine generating units using coal for fuel. The nameplate rating for Montana-Dakota's ownership interest in these four stations (including interests in the Big Stone Station and the Coyote Station, aggregating 22.7 percent and 25.0 percent, respectively) is 327,758 kW. Three combustion turbine peaking stations, a wind electric generating facility and a heat recovery electric generating facility supply the balance of Montana-Dakota's interconnected system electric generating capability.

In September 2005, Montana-Dakota entered into a contract for seasonal capacity from a neighboring utility, starting at 85 MW in 2007, increasing to 105 MW in 2011, with an option for capacity in 2012. In April 2007, Montana-Dakota entered into a contract for seasonal capacity of 10 MW in May through October of each year continuing through 2010. In August 2009, Montana-Dakota entered into a contract for capacity of 110 MW, 115 MW and 120 MW annually for the three-year period from June 1 to May 31, 2013, 2014 and 2015, respectively. Energy also will be purchased as needed from the Midwest ISO market. In 2009, Montana-Dakota purchased approximately 17 percent of its net kWh needs for its interconnected system through the Midwest ISO market.

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

Generating Station	Type	Nameplate Rating (kW)	Summer Capability (kW)	2009 Net Generation (kWh in thousands)
North Dakota:				
Coyote*	Steam	103,647	106,750	625,979
Heskett	Steam	86,000	102,730	556,757
Williston	Combustion Turbine	7,800	9,600	(81) **
Glen Ullin	Heat Recovery	7,500	***	10,271
South Dakota:				
Big Stone*	Steam	94,111	107,500	624,595
Montana:				
Lewis & Clark	Steam	44,000	52,300	316,532
Glendive	Combustion Turbine	77,347	79,610	1,950
Miles City	Combustion Turbine	23,150	24,500	(28) **
Diamond Willow	Wind	19,500	3,910	67,690
		463,055	486,900	2,203,665

* Reflects Montana-Dakota's ownership interest.
** Station use, to meet MAPP's accreditation requirements, exceeded generation.
*** Pending accreditation.

Virtually all of the current fuel requirements of the Coyote, Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland under contracts that expire in May 2016, April 2011 and December 2012, respectively. The Coyote coal supply agreement provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station or 30,000 tons per week, whichever may be the greater quantity at contracted pricing. The maximum quantity of coal during the term of the agreement, and any extension, is 75 million tons. The Heskett and Lewis & Clark coal supply agreements provide for the purchase of coal necessary

to supply the coal requirements of these stations at contracted pricing. Montana-Dakota estimates the Heskett and Lewis & Clark coal requirement to be in the range of 500,000 to 600,000 tons, and 250,000 to 350,000 tons per contract year, respectively.

Montana-Dakota has a coal supply agreement, which meets the majority of the Big Stone Station’s fuel requirements, for the purchase of 1.0 million tons of coal in 2010 with Kennecott at contracted pricing.

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

Years ended December 31,	2009	2008	2007
Average cost of coal per MMBtu	$1.52	$1.49	$1.29
Average cost of coal per ton	$22.05	$21.45	$18.71

The maximum electric peak demand experienced to date attributable to sales to retail customers on the interconnected system was 525,643 kW in July 2007. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the peak demand growth rate through 2015 will approximate two percent annually.

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 contracts. For additional information regarding potential power generation projects, see Item 7 – MD&A – Prospective Information – Electric.

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

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date 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 74,000 kW of capacity annually through December 31, 2016. On April 9, 2009, Montana-Dakota exercised an option to purchase a 25 percent interest in the Wygen III electric generating facility under construction by Black Hills Power to serve a portion of the needs of its Sheridan-area customers. The plant is expected to be commercial in the second quarter of 2010, and will replace 25 MW of capacity and energy purchased under the power supply contract. Montana-Dakota received a Certificate of Public Convenience and Necessity from the WYPSC on July 29, 2008, for ownership of Wygen III.

Montana-Dakota is subject to competition in varying degrees, in certain areas, from rural electric cooperatives, on-site generators, co-generators and municipally owned systems. In addition, competition in varying degrees exists between electricity and alternative forms of energy such as natural gas.

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

On August 14, 2009, Montana-Dakota filed an application with the WYPSC for an electric rate increase. For additional information, see Item 8 – Note 18.

In November 2009, a decision was made by the Big Stone Station II participants not to proceed with the project. For additional information, see Item 8 – Note 18.

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

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which they operate. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. Title V Operating Permits for the Big Stone Station and the Lewis & Clark Station were renewed in 2009. In August 2009, an application for renewal of the Heskett Station Title V Operating Permit was submitted. On February 25, 2009, a Montana Air Quality Permit application was granted for the Lewis & Clark Station to obtain a mercury emissions limit and approve its proposed mercury emissions control strategy.

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.

In June 2008, the Sierra Club filed a complaint in the South Dakota Federal District Court against Montana-Dakota and the two other co-owners of the Big Stone Station. For more information regarding this complaint, see Item 8 – Note 19.

Montana-Dakota incurred $5.9 million of environmental capital expenditures in 2009. Capital expenditures are estimated to be $1.7 million, $5.0 million and $6.5 million in 2010, 2011 and 2012, respectively, to maintain environmental compliance as new emission controls are required. Projects will include sulfur-dioxide, nitrogen oxide and mercury control equipment installation at electric generating stations. Montana-Dakota's capital and operational expenditures could also be affected in a variety of ways by potential new GHG legislation or regulation. In particular, such legislation or regulation would likely increase capital expenditures for renewable energy resources and operational costs associated with GHG emissions compliance until carbon capture technology becomes economical, at which time capital expenditures may be necessary to incorporate such technology into existing or new generating facilities. Montana-Dakota expects that it will recover the operational and capital expenditures for GHG regulatory compliance in its rates consistent with the recovery of other reasonable costs of complying with environmental laws and regulations.

Natural Gas Distribution

General The Company's natural gas distribution operations consist of Montana-Dakota, Great Plains, Cascade and Intermountain which sell natural gas at retail, serving over 829,000 residential, commercial and industrial customers in 333 communities and adjacent rural areas across eight states as of December 31, 2009, and provide natural gas transportation services to certain customers on their systems. These services are provided through distribution systems aggregating approximately 17,000 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. As of December 31, 2009, the natural gas distribution operations' net natural gas distribution plant investment approximated $909.9 million.

The percentage of the natural gas distribution operations' 2009 natural gas utility operating sales revenues by jurisdiction is as follows: Idaho – 32 percent; Washington – 30 percent; North Dakota – 11 percent; Oregon – 9 percent; Montana – 7 percent; South Dakota – 6 percent; Minnesota – 3 percent; and Wyoming – 2 percent. The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Dickinson, Wahpeton, Williston, Minot and Jamestown; central and eastern Oregon, including Bend and Pendleton; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton, Longview, Moses Lake, Mount Vernon, Tri-Cities, Walla Walla and Yakima; and northern Wyoming, including Sheridan. These markets are highly seasonal and sales volumes depend largely on the weather, the effects of which are mitigated in certain jurisdictions by a weather normalization mechanism discussed in Regulatory Matters.

Competition in varying degrees exists between natural gas and other fuels and forms of energy. The natural gas distribution operations have established various natural gas transportation service rates for their distribution businesses to retain interruptible commercial and industrial loads. Certain of these services include transportation under flexible rate schedules whereby interruptible customers can avail themselves of the advantages of open access transportation on regional transmission pipelines, including the systems of Williston Basin, Northern Border Pipeline Company, Northern Natural Gas Company, South Dakota Intrastate Pipeline, Viking Gas Transmission Company, Northwest Pipeline GP and Gas Transmission Northwest Corporation. 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 by Williston Basin, South Dakota Intrastate Pipeline Company, Northern Border Pipeline Company, Viking Gas Transmission Company, Northern Natural Gas Company, Source Gas, TransCanada Foothills System, TransCanada NOVA System, Northwestern Energy, Northwest Pipeline GP, TransCanada Gas Transmission Northwest Corporation and Spectra Energy Transmission West. 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 Williston Basin, Northern Natural Gas Company, Questar Pipeline and Northwest Pipeline GP. In addition, certain of the operations have entered into natural gas supply management agreements with Sequent Energy Management, IGI Resources Inc. and Tenaska Gas Storage. 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, and has also received approval of a decoupling mechanism in Washington that allows it to recover margin differences resulting from customer conservation. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

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

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

The natural gas distribution operations did not incur any material environmental expenditures in 2009 and, except as to what may be ultimately determined with regard to the issues described later, do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations in relation to the natural gas distribution operations through 2012.

Montana-Dakota has had an economic interest in five historic manufactured gas plants within its service territory, none of which are currently being actively investigated, and for which any remediation expenses are not expected to be material. Cascade has had an economic interest in nine former manufactured gas plants within its service territory. Cascade has been involved with other PRPs in the investigation of a manufactured gas plant site in Oregon, with remediation of this site pending additional investigation. See Item 8 – Note 19 for a further discussion of this site and for two additional sites for which Cascade has received claim notice. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers.

Construction Services

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

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

MDU Construction Services operates a fleet of owned and leased trucks and trailers, support vehicles and specialty construction equipment, such as backhoes, excavators, trenchers, generators, boring machines and cranes. In addition, as of December 31, 2009, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, warehousing, storage and vehicle shops. At December 31, 2009, MDU Construction Services' net plant investment was approximately $48.5 million.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2009, was approximately $383 million compared to $604 million at December 31, 2008. MDU Construction Services expects to complete a significant amount of this backlog during the year ending December 31, 2010. 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 customer's 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 2009 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2012.

Pipeline and Energy Services
General Williston Basin, the regulated business of WBI Holdings, owns and operates over 3,700 miles of transmission, gathering and storage lines and owns or leases and operates 33 compressor stations in Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields in Montana and Wyoming provide storage services to local distribution companies, producers, natural gas marketers and others, and serve to enhance system deliverability. Williston Basin's system is strategically located near five natural gas producing basins, making natural gas supplies available to Williston Basin's transportation and storage customers. The system has 11 interconnecting points with other pipeline facilities allowing for the receipt and/or delivery of natural gas to and from other regions of the country and from Canada. At December 31, 2009, Williston Basin's net plant investment was approximately $287.3 million. Under the Natural Gas Act, as amended, Williston Basin is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters.

Bitter Creek, the nonregulated pipeline business, owns and operates gathering facilities in Colorado, Kansas, Montana and Wyoming. Bitter Creek also owns a one-sixth interest in the assets of various offshore gathering pipelines, an associated onshore pipeline and related processing facilities in Texas. In total, these facilities include over 1,900 miles of field gathering lines and 88 owned or leased compression stations, some of which interconnect with Williston Basin's system. In 2009, the Company acquired the assets of a cathodic protection company. This acquisition was not material to the Company. Bitter Creek also provides a variety of energy-related services such as water hauling, contract compression operations, measurement services and energy efficiency product sales and installation services to large end-users.

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

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, 2009, represented 50 percent of Williston Basin's subscribed firm transportation contract demand. Montana-Dakota has firm transportation agreements with Williston Basin expiring November 2010 through June 2012. In addition, Montana-Dakota has a contract with Williston Basin to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2015.

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

System Supply Williston Basin's underground natural gas storage facilities have a certificated storage capacity of approximately 353 Bcf, including 193 Bcf of working gas capacity, 85 Bcf of cushion gas and 75 Bcf of native gas. The native gas includes an estimated 29 Bcf of recoverable gas. Williston Basin's storage facilities enable its customers to purchase natural gas at more uniform daily volumes throughout the year and 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 have helped support Williston Basin's supply needs. This includes new natural gas supply associated with the continued development of the Bakken area in Montana and North Dakota. The Powder River Basin, including the Company's CBNG assets, also provides a nontraditional natural gas supply to the Williston Basin system. For additional information regarding CBNG legal proceedings, see Item 1A – Risk Factors and Item 8 – Note 19. 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.

Regulatory Matters and Revenues Subject to Refund In December 1999, Williston Basin filed a general natural gas rate change application with the FERC. For additional information, see Item 8 – Note 18.

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 2009 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2012.

Natural Gas and Oil Production

General Fidelity is involved in the acquisition, exploration, development and production of natural gas and oil resources. Fidelity's activities include the acquisition of producing properties and leaseholds with potential development opportunities, exploratory drilling and the operation and development of natural gas and oil production properties. Fidelity continues to seek additional reserve and production growth opportunities through these activities. Future growth is dependent upon its success in these endeavors. Fidelity shares revenues and expenses from the development of specified properties in proportion to its ownership interests.

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

Rocky Mountain

Fidelity's properties in this region are primarily in Colorado, Montana, North Dakota, Utah and Wyoming. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Bonny Field in eastern Colorado, the Baker Field in southeastern Montana and southwestern North Dakota, the Bowdoin area in north-central Montana, the Powder River Basin of Montana and Wyoming, the Bakken area in North Dakota, the Paradox Basin of Utah, and the Big Horn Basin of Wyoming. Fidelity also owns nonoperated natural gas and oil interests and undeveloped acreage positions in this region.

Mid-Continent/Gulf States

This region includes properties in Alabama, Louisiana, New Mexico, Texas and the Offshore Gulf of Mexico. The Offshore Gulf of Mexico interests are primarily located in the shallow waters off the coasts of Texas and Louisiana. Fidelity owns in fee or holds natural gas and oil leases for the properties it operates that are in the Tabasco and Texan Gardens fields of Texas and natural gas properties in Rusk County in eastern Texas. In addition, Fidelity owns several nonoperated interests and undeveloped acreage positions in this region.

Operating Information Annual net production by region for 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.

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Annual net production by region for 2008 was as follows:

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

* Baker field and Bowdoin field represent 28 percent and 18 percent, respectively, of total annual net natural gas production.

Annual net production by region for 2007 was as follows:

Region	Natural Gas (MMcf) *	Oil (MBbls)	Total (MMcfe)	Percent of Total
Rocky Mountain	48,832	1,287	56,553	74 %
Mid-Continent/Gulf States	13,966	1,078	20,435	26
Total	62,798	2,365	76,988	100 %

* Baker field and Bowdoin field represent 31 percent and 19 percent, respectively, of total annual net natural gas production.

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, 2009, were as follows:

	Gross*	Net**
Productive wells:		
Natural gas	3,869	3,121
Oil	3,706	258
Total	7,575	3,379
Developed acreage (000's)	720	400
Undeveloped acreage (000's)	834	449

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

Exploratory and Development Wells The following table reflects activities related to Fidelity's natural gas and oil wells drilled and/or tested during 2009, 2008 and 2007:

	Net Exploratory			Net Development			
	Productive	Dry Holes	Total	Productive	Dry Holes	Total	Total
2009	1	2	3	104	–	104	107
2008	11	4	15	251	9	260	275
2007	4	5	9	317	16	333	342

At December 31, 2009, there were 74 gross (60 net) wells in the process of drilling or under evaluation, 70 of which were development wells and 4 of which were exploratory wells. These wells are not included in the previous table. Fidelity expects to complete the drilling and testing of the majority of these wells within the next 12 months.

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

Competition The natural gas and oil industry is highly competitive. Fidelity competes with a substantial number of major and independent natural gas and oil companies in acquiring producing properties and new leases for future exploration and development, and in securing the equipment, services and expertise necessary to explore, develop and operate its properties.

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

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

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

In connection with production operations, Fidelity has incurred certain capital expenditures related to water handling. For 2009, capital expenditures for water handling in compliance with current laws and regulations were approximately $222,000 and are estimated to be approximately $3.0 million, $8.9 million and $9.2 million in 2010, 2011 and 2012, respectively. These water handling costs are primarily related to the CBNG properties. For more information regarding CBNG litigation, see Item 1A – Risk Factors and Item 8 – Note 19.

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 and are reviewed and approved by management. The technical person responsible for overseeing the preparation of the reserve estimates holds a bachelor of science degree in geological engineering, has substantial practical 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 Company, L.P. reviewed the Company’s proved reserve quantity estimates as of December 31, 2009. The technical person at Ryder Scott Company, L.P. primarily responsible for overseeing the reserves

audit holds a bachelor of science degree in mechanical engineering, has extensive experience estimating and auditing reserves attributable to oil and gas properties, and is a member of multiple professional organizations.

Fidelity's recoverable proved reserves by region at December 31, 2009, are as follows:

Region	Natural Gas (MMcf)	Oil (MBbls)	Total (MMcfe)	Percent of Total		PV-10 Value* (in millions)
Rocky Mountain	309,359	24,354	455,482	70	%	$563.9
Mid-Continent/Gulf States	139,066	9,862	198,242	30		225.3
Total reserves	448,425	34,216	653,724	100	%	789.2
Discounted future income taxes						130.4
Standardized measure of discounted future net cash flows relating to proved reserves						$658.8

* 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 $459 million in backlog at December 31, 2009, compared to $453 million at December 31, 2008. The Company anticipates that a significant amount of the current backlog will be completed during the year ending December 31, 2010.

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 above are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by 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 2007 through 2009. 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, 2009, and sales for the years ended December 31, 2009, 2008 and 2007:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease	Reserve Life
Production Area	owned	leased	owned	leased	2009	2008	2007		Expiration	(years)
Anchorage, AK	-	-	1	-	891	1,267	1,118	17,554	N/A	16
Hawaii	-	6	-	-	1,940	2,467	3,081	63,622	2011-2064	25
Northern CA	-	-	9	1	1,215	2,054	2,534	49,393	2014	26
Southern CA	-	2	-	-	337	106	69	94,887	2035	Over 100
Portland, OR	1	3	6	3	2,718	4,074	5,372	248,243	2010-2055	61
Eugene, OR	3	4	4	1	1,097	1,633	2,007	172,258	2010-2046	Over 100
Central OR/WA/Idaho	1	2	4	3	1,436	1,686	2,652	107,632	2010-2021	56
Southwest OR	5	4	12	7	1,871	2,248	3,686	102,561	2011-2048	39
Central MT	-	-	3	2	1,220	2,086	2,424	27,136	2013-2027	14
Northwest MT	-	-	9	3	1,289	1,198	1,318	48,033	2010-2020	38
Wyoming	-	-	1	2	655	720	116	14,041	2013-2019	28
Central MN	-	1	38	33	1,868	1,367	2,639	83,549	2010-2028	43
Northern MN	2	-	17	6	838	333	753	28,262	2010-2016	44
ND/SD	-	-	2	24	699	876	943	39,428	2010-2031	47
Iowa	-	2	1	14	545	1,405	1,592	10,544	2010-2018	9
Texas	1	2	-	2	1,080	1,619	1,290	18,348	2010-2025	14
Sales from other sources					4,296	5,968	5,318			
					23,995	31,107	36,912	1,125,491		

The 1.1 billion tons of estimated aggregate reserves at December 31, 2009, is comprised of 472 million tons that are owned and 653 million tons that are leased. Approximately 51 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 22 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2007 through 2009 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 53 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

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The following table summarizes Knife River's aggregate reserves at December 31, 2009, 2008 and 2007, and reconciles the changes between these dates:

	2009	2008	2007
		(000's of tons)	
Aggregate reserves:			
Beginning of year	1,145,161	1,215,253	1,248,099
Acquisitions	21,400	27,650	29,740
Sales volumes*	(19,699)	(25,139)	(31,594)
Other**	(21,371)	(72,603)	(30,992)
End of year	1,125,491	1,145,161	1,215,253

* Excludes sales from other sources.
** Includes property sales and revisions of previous estimates.

Environmental Matters Knife River's construction materials and contracting operations are subject to regulation customary for such operations, including federal, state and local environmental compliance and reclamation regulations. Except as to what may be ultimately determined with regard to the Portland, Oregon, Harbor Superfund Site issue described later, Knife River believes it is in substantial compliance with these regulations. Individual permits applicable to Knife River’s various operations are managed largely by local operations, particularly as they relate to application, modification, renewal, compliance, and reporting procedures.

Knife River's asphalt and ready-mixed concrete manufacturing plants and aggregate processing plants are subject to Clean Air Act and Clean Water Act requirements for controlling air emissions and water discharges. Some mining and construction activities also are subject to these laws. In most of the states where Knife River operates, these regulatory programs have been delegated to state and local regulatory authorities. Knife River's facilities also are subject to RCRA as it applies to the management of hazardous wastes and underground storage tank systems. These programs also have generally been delegated to the state and local authorities in the states where Knife River operates. Knife River's facilities must comply with requirements for managing wastes and underground storage tank systems.

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

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

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

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

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

Knife River's Gascoyne surface coal mine last produced coal in 1995 but continues to be subject to reclamation requirements of the SMCRA, as well as the North Dakota Surface Mining Act. Portions of the Gascoyne Mine remain under reclamation bond until the 10-year revegetation liability period has expired. A portion of the original permit has been released from bond and additional areas are currently in the process of having the bond released. Knife River's intention is to request bond release as soon as it is deemed possible with all final bond release applications being filed by 2013.

Knife River did not incur any material environmental expenditures in 2009 and, except as to what may be ultimately determined with regard to the issue described below, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2012.

In December 2000, MBI was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by MBI in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For additional information, see Item 8 – Note 19.

Item 1A. Risk Factors

The Company's business and financial results are subject to a number of risks and uncertainties, including those set forth below and in other documents that it files with the SEC. The factors and the other matters discussed herein are important factors that could cause actual results or outcomes for the Company to differ materially from those discussed in the forward-looking statements included elsewhere in this document.

Economic Risks
The Company's natural gas and oil production and pipeline and energy services businesses are dependent on factors, including commodity prices and commodity price basis differentials, which are subject to various external influences that cannot be controlled.

These factors include: fluctuations in natural gas and oil prices; fluctuations in commodity price basis differentials; availability of economic supplies of natural gas; drilling successes in natural gas and oil operations; the timely receipt of necessary permits and approvals; the ability to contract for or to secure necessary drilling rig and service contracts and to retain employees to drill for and develop reserves; the ability to acquire natural gas and oil properties; and other risks incidental to the operations of natural gas and oil wells. Volatility in natural gas and oil prices could negatively affect the results of operations and cash flows of the Company's natural gas and oil production and pipeline and energy services businesses.

The regulatory approval, permitting, construction, startup and operation of power generation facilities may involve unanticipated changes or delays that could negatively impact the Company's business and its results of operations and cash flows.

The construction, startup and operation of power generation facilities involve 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 and, as a result, 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 certain of the Company's products and services. Continued economic volatility could adversely impact the Company's results of operations and cash flows. Changing market conditions could negatively affect the market value of assets held in the Company’s pension and other postretirement benefit plans and may increase the amount and accelerate the timing of required funding contributions.

The Company relies on financing sources and capital markets. Access to these markets may be adversely affected by factors beyond the Company's control. If the Company is unable to obtain economic financing in the future, the Company's ability to execute its business plans, make capital expenditures or pursue acquisitions that the Company may otherwise rely on for future growth could be impaired. As a result, the market value of the Company's common stock may be adversely affected. If the Company issues a substantial amount of common stock it could have a dilutive effect on its existing shareholders.

The Company relies on access to both short-term borrowings, including the issuance of commercial paper, and long-term capital markets as sources of liquidity for capital requirements not satisfied by its cash flow from operations. If the Company is not able to access capital at competitive rates, the ability to implement its business plans may be adversely affected. Market disruptions or a further downgrade of the Company's credit ratings may increase the cost of borrowing or adversely affect its ability to access one or more financial markets. Such disruptions could include:

- A severe prolonged economic downturn
- The bankruptcy of unrelated industry leaders in the same line of business
- Further deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks

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

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

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

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

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

Backlog consists of the uncompleted portion of services to be performed under job-specific contracts. Contracts are subject to delay, default or cancellation and the contracts in the Company’s backlog are subject to changes in the scope of services to be provided as well as adjustments to the costs relating to the applicable contracts. Backlog may also be affected by project delays or cancellations resulting from weather conditions, external market factors and

economic factors beyond the Company’s control, including the current economic slowdown. Accordingly, there is no assurance that backlog will be realized.

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

The process of estimating natural gas and oil reserves is complex. Reserve estimates are based on assumptions relating to natural gas and oil pricing, drilling and operating expenses, capital expenditures, taxes, timing of operations, and the percentage of interest owned by the Company in the well. 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
Some of the Company's operations are subject to extensive environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to extensive environmental laws and regulations affecting many aspects of its present and future operations including air quality, water quality, waste management and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, and delays as a result of ongoing litigation and administrative proceedings and compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions and CBNG development. These laws and regulations generally require the Company to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Public officials and entities, as well as private individuals and organizations, may seek injunctive relief or other remedies to enforce applicable environmental laws and regulations. The Company cannot predict the outcome (financial or operational) of any related litigation or administrative proceedings that may arise.

Existing environmental 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, require the installation of pollution control equipment or the initiation of 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, which 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 Company's electric generation operations could be adversely impacted by global climate change initiatives to reduce GHG emissions.

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 including the EPA’s proposed endangerment finding for GHGs which could lead to regulation of GHG under the Clean Air Act. 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 which comprise more than 70 percent of Montana-Dakota’s generating capacity. More than 90 percent of the electricity generated by Montana-Dakota is from coal-fired plants and Montana-Dakota has acquired a 25 MW ownership interest in the Wygen III coal-fired generation facility which is under construction near Gillette, Wyoming. Montana-Dakota also owns approximately 100 MW of natural gas- and oil-fired peaking plants. While there are many uncertainties regarding the future of GHG regulation, Montana-Dakota’s electric generating facilities may be subject to regulation under 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 the expansion of energy conservation efforts and/or the increased development of renewable energy sources, as well as instituting other mandates that could significantly increase the capital expenditures and operating costs at its fossil fuel-fired generating facilities. The most prominent federal legislative proposals are based on “cap and trade” programs which place a limit on GHG emissions from major emission sources such as the electric generating industry. The impact of a cap and trade program on Montana-Dakota would be determined by considerations such as the overall GHG emissions cap level, the scope and timeframe by which the cap level is decreased, the extent to which GHG offsets are allowed, whether allowances are given to new and existing emission sources, and the indirect impact on natural gas, coal and other fuel prices. Montana-Dakota’s ability to recover costs incurred to comply with new regulations and programs will also be important in determining the financial impact on the Company.

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

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

Fidelity’s operations are and have been the subject of numerous lawsuits filed in connection with its CBNG development in the Montana and Wyoming Powder River Basin. If the plaintiffs are successful in the current lawsuits, the ultimate outcome of the actions could have a material negative effect on Fidelity's existing CBNG operations and/or the future development of its CBNG properties.

The BER in March 2006 issued a decision in a rulemaking proceeding, initiated by the NPRC, that amends the non-degradation policy applicable to water discharged in connection with CBNG operations. The amended policy includes additional limitations on factors deemed harmful, thereby restricting water discharges even further than under previous standards. Due in part to this amended policy, in May 2006, the Northern Cheyenne Tribe commenced litigation in Montana state court challenging two five-year water discharge permits that the Montana DEQ granted to Fidelity in February 2006 and which are critical to Fidelity's ability to manage water produced under present and future CBNG operations. Although the Montana state court decided the case in favor of Fidelity and the Montana DEQ in January 2009, the case was appealed to the Montana Supreme Court in March 2009. In a separate proceeding in Montana state court, plaintiffs are challenging the ROD adopted by the MBOGC in 2003 and alleging that various water management tools, including Fidelity’s water discharge permits, allow for the “wasting” of water in violation of the Montana State Constitution. If these permits are set aside, Fidelity's CBNG operations in Montana could be significantly and adversely affected.

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

The Company is subject to regulation by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return, financing, industry rate structures, and recovery of purchased power and purchased gas costs. These governmental regulations significantly influence the Company’s operating environment and may affect its ability to recover costs from its customers. The Company is unable to predict the impact on operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on the Company’s results of operations 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.

Risks Relating to Foreign Operations

The value of the Company's investments in foreign operations may diminish due to political, regulatory and economic conditions and changes in currency exchange rates in countries where the Company does business.

The Company is subject to political, regulatory and economic conditions and changes in currency exchange rates in foreign countries where the Company does business. Significant changes in the political, regulatory or economic environment in these countries could negatively affect the value of the Company's investments located in these countries. Also, since the Company is unable to predict the fluctuations in the foreign currency exchange rates, these fluctuations may have an adverse impact on the Company's results of operations and cash flows.

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 directly influence the demand for electricity and natural gas, affect the price of energy commodities, affect the ability to perform services at the construction services and construction materials and contracting businesses and affect ongoing operation and maintenance and construction and drilling activities for the pipeline and energy services and natural gas and oil production businesses. In addition, severe weather can be destructive, causing outages, reduced natural gas and oil production, and/or property damage, which could require additional costs to be incurred. Physical changes to the planet could further change the intensity and frequency of severe weather conditions. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial condition and cash flows.

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

All of the Company's businesses are subject to increased competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. The construction materials products are marketed under highly competitive conditions and are subject to such competitive forces as price, service, delivery time and proximity to the customer. The electric utility and natural gas industries also are experiencing increased competitive pressures as a result of consumer demands, technological advances, volatility in natural gas prices and other factors. Pipeline and energy services competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. The natural gas and oil production business is subject to competition in the acquisition and development of natural gas and oil properties. The increase in competition could negatively affect the Company's results of operations, financial condition and cash flows.

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

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

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

The Company participates in various multi-employer pension plans for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under collective bargaining agreements. Pension expense for these plans is recognized as contributions are made. The amount of any increase or decrease in the Company’s required contributions to these multi-employer pension plans will depend upon many factors including the outcome of collective bargaining, actions taken by trustees who manage the plans, government regulations, the actual return on assets held in the plans and the potential payment of a withdrawal liability upon withdrawal from a plan, among other factors. Based on available information, the Company believes that many of the multi-employer plans to which it contributes are underfunded. The underfunded liabilities of these plans may result in increased future payments by the

Company and other participating employers. The Company’s risk of such increased payments may be greater if any of the participating employers in these underfunded plans withdraws from the plan due to insolvency and is not able to contribute an amount sufficient to fund the unfunded liabilities associated with its participants in the plan. The Company may experience increased operating expenses as a result of required contributions to multi-employer pension plans, which may have a material adverse effect on the Company’s results of operations and cash flows.

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, and/or available supplies 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 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.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2009.

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 2009 and 2008 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Per Share
2009			
First quarter	$ 22.89	$ 12.79	$ .1550
Second quarter	19.76	15.70	.1550
Third quarter	21.16	17.44	.1550
Fourth quarter	24.22	19.96	.1575
			$ .6225
2008			
First quarter	$ 27.83	$ 23.08	$ .1450
Second quarter	35.25	24.70	.1450
Third quarter	35.34	26.03	.1550
Fourth quarter	29.50	15.50	.1550
			$ .6000

As of December 31, 2009, the Company's common stock was held by approximately 15,500 stockholders of record.

Item 6. Selected Financial Data

	2009 *	2008 **	2007	2006	2005	2004
Selected Financial Data						
Operating revenues (000's):						
Electric	$196,171	$208,326	$193,367	$187,301	$181,238	$178,803
Natural gas distribution	1,072,776	1,036,109	532,997	351,988	384,199	316,120
Construction services	819,064	1,257,319	1,103,215	987,582	687,125	426,821
Pipeline and energy services	307,827	532,153	447,063	443,720	477,311	354,164
Natural gas and oil production	439,655	712,279	514,854	483,952	439,367	342,840
Construction materials and contracting	1,515,122	1,640,683	1,761,473	1,877,021	1,604,610	1,322,161
Other	9,487	10,501	10,061	8,117	6,038	4,423
Intersegment eliminations	(183,601)	(394,092)	(315,134)	(335,142)	(375,965)	(272,199)
	$4,176,501	$5,003,278	$4,247,896	$4,004,539	$3,403,923	$2,673,133
Operating income (loss) (000's):						
Electric	$36,709	$35,415	$31,652	$27,716	$29,038	$26,776
Natural gas distribution	76,899	76,887	32,903	8,744	7,404	1,820
Construction services	44,255	81,485	75,511	50,651	28,171	(5,757)
Pipeline and energy services	69,388	49,560	58,026	57,133	43,507	29,570
Natural gas and oil production	(473,399)	202,954	227,728	231,802	230,383	178,897
Construction materials and contracting	93,270	62,849	138,635	156,104	105,318	86,030
Other	(219)	2,887	(7,335)	(9,075)	(5,298)	(3,954)
	$(153,097)	$512,037	$557,120	$523,075	$438,523	$313,382
Earnings (loss) on common stock (000's):						
Electric	$24,099	$18,755	$17,700	$14,401	$13,940	$12,790
Natural gas distribution	30,796	34,774	14,044	5,680	3,515	2,182
Construction services	25,589	49,782	43,843	27,851	14,558	(5,650)
Pipeline and energy services	37,845	26,367	31,408	32,126	22,867	13,806
Natural gas and oil production	(296,730)	122,326	142,485	145,657	141,625	110,779
Construction materials and contracting	47,085	30,172	77,001	85,702	55,040	50,707
Other	7,357	10,812	(4,380)	(4,324)	13,061	15,967
Earnings (loss) on common stock before income from discontinued operations	(123,959)	292,988	322,101	307,093	264,606	200,581

Income from discontinued operations, net of tax	—	—	109,334	7,979	9,792	5,801
	$(123,959)	$292,988	$431,435	$315,072	$274,398	$206,382
Earnings (loss) per common share before discontinued operations - diluted	$(.67)	$1.59	$1.76	$1.69	$1.47	$1.14
Discontinued operations, net of tax	—	—	.60	.05	.06	.03
	$(.67)	$1.59	$2.36	$1.74	$1.53	$1.17
Common Stock Statistics						
Weighted average common shares outstanding - diluted (000's)	185,175	183,807	182,902	181,392	179,490	176,117
Dividends per common share	$.6225	$.6000	$.5600	$.5234	$.4934	$.4667
Book value per common share	$13.61	$14.95	$13.80	$11.88	$10.43	$9.39
Market price per common share (year end)	$23.60	$21.58	$27.61	$25.64	$21.83	$17.79
Market price ratios:						
Dividend payout	N/A	38 %	24 %	30 %	32 %	40 %
Yield	2.7 %	2.9 %	2.1 %	2.1 %	2.3 %	2.7 %
Price/earnings ratio	N/A	13.6 x	11.7 x	14.7 x	14.3 x	15.2 x
Market value as a percent of book value	173.4 %	144.3 %	200.1 %	215.8 %	209.2 %	189.4 %
Profitability Indicators						
Return on average common equity	(4.9)%	11.0 %	18.5 %	15.6 %	15.7 %	13.2 %
Return on average invested capital	(1.7)%	8.0 %	13.1 %	10.6 %	10.8 %	9.4 %
Fixed charges coverage, including preferred dividends	— ***	5.3 x	6.4 x	6.4 x	6.6 x	4.8 x
General						
Total assets (000's)	$5,990,952	$6,587,845	$5,592,434	$4,903,474	$4,423,562	$3,733,521
Total debt (000's)	$1,509,606	$1,752,402	$1,310,163	$1,254,582	$1,206,510	$945,487
Capitalization ratios:						
Common equity	63 %	61 %	66 %	63 %	61 %	63 %
Preferred stocks	—	—	—	—	—	1
Total debt	37	39	34	37	39	36
	100 %	100 %	100 %	100 %	100 %	100 %

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

Notes:

- Common stock share amounts reflect the Company's three-for-two common stock split effected in July 2006.
- Cascade and Intermountain, natural gas distribution businesses, were acquired on July 2, 2007, and October 1, 2008, respectively. For further information, see Item 8 – Note 2.

	2009	2008	2007	2006	2005	2004
Electric						
Retail sales (thousand kWh)	2,663,560	2,663,452	2,601,649	2,483,248	2,413,704	2,303,460
Sales for resale (thousand kWh)	90,789	223,778	165,639	483,944	615,220	821,516
Electric system summer generating and firm purchase capability - kW (Interconnected system)	594,700	597,250	571,160	547,485	546,085	544,220
Demand peak – kW (Interconnected system)	525,643	525,643	525,643	485,456	470,470	470,470
Electricity produced (thousand kWh)	2,203,665	2,538,439	2,253,851	2,218,059	2,327,228	2,552,873
Electricity purchased (thousand kWh)	682,152	516,654	576,613	833,647	892,113	794,829
Average cost of fuel and purchased power per kWh	$.023	$.025	$.025	$.022	$.020	$.019
Natural Gas Distribution*						
Sales (Mdk)	102,670	87,924	52,977	34,553	36,231	36,607
Transportation (Mdk)	132,689	103,504	54,698	14,058	14,565	13,856
Degree days (% of normal)						
Montana-Dakota	104 %	103 %	93 %	87 %	91 %	91 %
Cascade	105 %	108 %	102 %	—	—	—
Intermountain	107 %	90 %	—	—	—	—
Pipeline and Energy Services						
Transportation (Mdk)	163,283	138,003	140,762	130,889	104,909	114,206
Gathering (Mdk)	92,598	102,064	92,414	87,135	82,111	80,527
Natural Gas and Oil Production						
Production:						
Natural gas (MMcf)	56,632	65,457	62,798	62,062	59,378	59,750
Oil (MBbls)	3,111	2,808	2,365	2,041	1,707	1,747
Total production (MMcfe)	75,299	82,303	76,988	74,307	69,622	70,234
Average realized prices (including hedges):						
Natural gas (per Mcf)	$5.16	$7.38	$5.96	$6.03	$6.11	$4.69
Oil (per barrel)	$47.38	$81.68	$59.26	$50.64	$42.59	$34.16
Average realized prices (excluding hedges):						
Natural gas (per Mcf)	$2.99	$7.29	$5.37	$5.62	$6.87	$4.90
Oil (per barrel)	$49.76	$82.28	$59.53	$51.73	$48.73	$37.75
Proved reserves:						
Natural gas (MMcf)	448,425	604,282	523,737	538,100	489,100	453,200
Oil (MBbls)	34,216	34,348	30,612	27,100	21,200	17,100

Total reserves (MMcfe)	653,724	810,371	707,409	700,700	616,400	555,900
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	23,995	31,107	36,912	45,600	47,204	43,444
Asphalt (tons)	6,360	5,846	7,062	8,273	9,142	8,643
Ready-mixed concrete (cubic yards)	3,042	3,729	4,085	4,588	4,448	4,292
Aggregate reserves (000’s tons)	1,125,491	1,145,161	1,215,253	1,248,099	1,273,696	1,257,498

* Cascade and Intermountain were acquired on July 2, 2007, and October 1, 2008, respectively. For further information, see Item 8 – Note 2.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

Overview

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

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

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities and the issuance from time to time of debt and equity securities. Due to recent economic volatility, the Company in 2009 increased its focus on the use of operating cash flows to substantially fund capital expenditures. In the event that access to the commercial paper markets were to become unavailable, the Company may need to borrow under its credit agreements. For more information on the Company's net capital expenditures, see Liquidity and Capital Commitments.

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

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide competitively priced energy to customers while working with them to ensure efficient usage. Both the electric and natural gas distribution segments continually seek opportunities for growth and expansion of their customer base through extensions of existing operations, including electric generation and transmission build-out, and through selected acquisitions of companies and properties at prices that will provide stable cash flows and an opportunity for the Company to earn a competitive return on investment.

Challenges Both segments are subject to extensive regulation in the state jurisdictions where they conduct operations with respect to costs and permitted returns on investment as well as subject to certain operational regulations at the federal level. The ability of these segments to grow through acquisitions is subject to significant competition from other energy providers. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of electric generating facilities and transmission lines may be subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which may necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could increase the price and decrease the retail demand for electricity and natural gas.

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

Challenges This segment operates in highly competitive markets with many jobs subject to competitive bidding. Maintenance of effective operational and cost controls, retention of key personnel, managing through downturns in the economy and effective management of working capital are ongoing challenges.

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

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

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

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

Construction Materials and Contracting
Strategy Focus on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthen long-term, strategic aggregate reserve position through purchase and/or lease opportunities; enhance profitability through cost containment, margin discipline and vertical integration of the segment's operations; and continue growth through organic and acquisition opportunities. Ongoing efforts to increase margin are being pursued through the implementation of a variety of continuous improvement programs, including corporate purchasing of equipment, parts and commodities (liquid asphalt, diesel fuel, cement and other materials), and negotiation of contract price escalation provisions. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and

asphalt, with control of and access to adequate quantities of permitted aggregate reserves being significant. A key element of the Company’s long-term strategy for this business is to further expand its presence, through acquisition, 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. This business unit expects to continue cost containment efforts and a greater emphasis on industrial, energy and public works projects. Significant volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel continue to be a concern. Increased competition in certain construction markets has also lowered margins.

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,	2009	2008	2007
	(Dollars in millions, where applicable)		
Electric	$24.1	$18.7	$17.7
Natural gas distribution	30.8	34.8	14.0
Construction services	25.6	49.8	43.8
Pipeline and energy services	37.8	26.4	31.4
Natural gas and oil production	(296.7)	122.3	142.5
Construction materials and contracting	47.1	30.2	77.0
Other	7.3	10.8	(4.3)
Earnings (loss) before discontinued operations	(124.0)	293.0	322.1
Income from discontinued operations, net of tax	—	—	109.3
Earnings (loss) on common stock	$(124.0)	$293.0	$431.4
Earnings (loss) per common share – basic:			
Earnings (loss) before discontinued operations	$(.67)	$1.60	$1.77
Discontinued operations, net of tax	—	—	.60
Earnings (loss) per common share – basic	$(.67)	$1.60	$2.37
Earnings (loss) per common share – diluted:			
Earnings (loss) before discontinued operations	$(.67)	$1.59	$1.76
Discontinued operations, net of tax	—	—	.60
Earnings (loss) per common share – diluted	$(.67)	$1.59	$2.36
Return on average common equity	(4.9)%	11.0%	18.5%

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

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

Partially offsetting these decreases were:

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

2008 compared to 2007 Consolidated earnings for 2008 decreased $138.4 million from the prior year due to:

- The absence in 2008 of income from discontinued operations, net of tax, largely related to the gain on the sale of the Company's domestic independent power production assets and earnings related to an electric generating facility construction project
- An $84.2 million after-tax noncash write-down of natural gas and oil properties as well as higher depreciation, depletion and amortization expense, production taxes and lease operating costs at the natural gas and oil production business
- Decreased earnings at the construction materials and contracting business, primarily construction workloads and margins, as well as product volumes from existing operations, that were significantly lower as a result of the economic downturn

Partially offsetting these decreases were higher average natural gas and oil prices as well as increased oil and natural gas production at the natural gas and oil production business; increased earnings at the natural gas distribution business, largely due to the July 2007 acquisition of Cascade and the October 2008 acquisition of Intermountain; and higher construction workloads at the construction 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,	2009	2008	2007
	(Dollars in millions, where applicable)		
Operating revenues	$196.2	$208.3	$193.4
Operating expenses:			
Fuel and purchased power	65.7	75.4	69.6
Operation and maintenance	60.7	64.8	61.7
Depreciation, depletion and amortization	24.7	24.0	22.5
Taxes, other than income	8.4	8.7	7.9
	159.5	172.9	161.7
Operating income	36.7	35.4	31.7
Earnings	$24.1	$18.7	$17.7
Retail sales (million kWh)	2,663.5	2,663.4	2,601.7
Sales for resale (million kWh)	90.8	223.8	165.6
Average cost of fuel and purchased power per kWh	$.023	$.025	$.025

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

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

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

2008 compared to 2007 Electric earnings increased $1.0 million (6 percent) compared to the prior year due to:

- Higher retail sales margins, largely due to the implementation of higher rates in Montana, and increased retail sales volumes of 2 percent
- Increased sales for resale volumes of 35 percent, primarily due to the addition of the wind-powered electric generating station near Baker, Montana, and higher plant availability

Partially offsetting these increases were:

- Higher operation and maintenance expense of $1.7 million (after tax), primarily higher payroll and benefit-related costs, as well as higher scheduled maintenance outage costs at electric generating facilities
- Increased interest expense of $1.2 million (after tax)
- Higher depreciation, depletion and amortization expense of $900,000 (after tax), largely due to higher property, plant and equipment balances

Natural Gas Distribution

Years ended December 31,	2009		2008		2007	
	(Dollars in millions, where applicable)					
Operating revenues	$1,072.8		$1,036.1		$533.0	
Operating expenses:						
Purchased natural gas sold	757.6		757.6		372.2	
Operation and maintenance	140.5		123.6		88.5	
Depreciation, depletion and amortization	42.7		32.6		19.0	
Taxes, other than income	55.1		45.4		20.4	
	995.9		959.2		500.1	
Operating income	76.9		76.9		32.9	
Earnings	$30.8		$34.8		$14.0	
Volumes (MMdk):						
Sales	102.7		87.9		53.0	
Transportation	132.7		103.5		54.7	
Total throughput	235.4		191.4		107.7	
Degree days (% of normal)*						
Montana-Dakota	104.4	%	102.7	%	92.9	%
Cascade	105.1	%	108.0	%	101.7	%
Intermountain	107.3	%	90.3	%	—	
Average cost of natural gas,						
including transportation, per dk**	$7.38		$8.14		$6.53	

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

** Regulated natural gas sales only.

Note: Cascade and Intermountain were acquired on July 2, 2007, and October 1, 2008, respectively. For further information, see Item 8 – Note 2.

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

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

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

2008 compared to 2007 The natural gas distribution business experienced an increase in earnings of $20.8 million (148 percent) compared to the prior year due to:

- Earnings of $18.4 million at Cascade and Intermountain, including a $4.4 million (after tax) gain on the sale of Cascade's natural gas management service, which were acquired on July 2, 2007, and October 1, 2008, respectively
    - Increased retail sales volumes from existing operations resulting from colder weather than last year

Construction Services

Years ended December 31,	2009	2008	2007
		(In millions)	
Operating revenues	$819.0	$1,257.3	$1,103.2
Operating expenses:			
Operation and maintenance	736.3	1,122.7	979.7
Depreciation, depletion and amortization	12.8	13.4	14.3
Taxes, other than income	25.7	39.7	33.7
	774.8	1,175.8	1,027.7
Operating income	44.2	81.5	75.5
Earnings	$25.6	$49.8	$43.8

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

2008 compared to 2007 Construction services earnings increased $6.0 million (14 percent) compared to the prior year, primarily due to higher construction workloads, largely in the Southwest region. Partially offsetting this increase were lower construction margins in certain regions.

Pipeline and Energy Services

Years ended December 31,	2009	2008	2007
	(Dollars in millions)		
Operating revenues	$307.8	$532.2	$447.1
Operating expenses:			
Purchased natural gas sold	138.8	373.9	291.7
Operation and maintenance	63.1	73.8	65.6
Depreciation, depletion and amortization	25.5	23.6	21.7
Taxes, other than income	11.0	11.3	10.1
	238.4	482.6	389.1
Operating income	69.4	49.6	58.0
Income from continuing operations	37.8	26.4	31.4
Income from discontinued operations, net of tax	—	—	.1
Earnings	$37.8	$26.4	$31.5
Transportation volumes (MMdk):			
Montana-Dakota	38.9	32.0	29.3
Other	124.4	106.0	111.5
	163.3	138.0	140.8
Gathering volumes (MMdk)	92.6	102.1	92.4

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

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

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

2008 compared to 2007 Pipeline and energy services earnings decreased $5.1 million (16 percent) largely due to:

- Lower storage services revenue of $3.1 million (after tax), largely related to lower storage balances and decreased volumes transported to storage of 31 percent
- Higher operation and maintenance expense, largely related to natural gas storage litigation, as previously discussed, as well as higher materials and payroll-related costs
- Higher depreciation, depletion and amortization expense of $1.3 million (after tax), largely due to higher property, plant and equipment balances

Partially offsetting these decreases were a 10 percent increase in off-system transportation volumes and demand fees, related to an expansion of the Grasslands system, and $3.0 million (after tax) of higher gathering volumes and rates.

Natural Gas and Oil Production

Years ended December 31,	2009	2008	2007
	(Dollars in millions, where applicable)		
Operating revenues:			
Natural gas	$292.3	$482.8	$374.1
Oil	147.4	229.3	140.1
Other	—	.2	.6
	439.7	712.3	514.8
Operating expenses:			
Purchased natural gas sold	—	.1	.3
Operation and maintenance:			
Lease operating costs	70.1	82.0	66.9
Gathering and transportation	24.0	24.8	20.4
Other	39.2	41.0	34.6
Depreciation, depletion and amortization	129.9	170.2	127.4
Taxes, other than income:			
Production and property taxes	29.1	54.7	36.7
Other	.8	.8	.8
Write-down of natural gas and oil properties	620.0	135.8	—
	913.1	509.4	287.1
Operating income (loss)	(473.4)	202.9	227.7
Earnings (loss)	$(296.7)	$122.3	$142.5
Production:			
Natural gas (MMcf)	56,632	65,457	62,798
Oil (MBbls)	3,111	2,808	2,365
Total Production (MMcfe)	75,299	82,303	76,988
Average realized prices (including hedges):			
Natural gas (per Mcf)	$5.16	$7.38	$5.96
Oil (per Bbl)	$47.38	$81.68	$59.26
Average realized prices (excluding hedges):			
Natural gas (per Mcf)	$2.99	$7.29	$5.37
Oil (per Bbl)	$49.76	$82.28	$59.53
Average depreciation, depletion and amortization rate, per equivalent Mcf	$1.64	$2.00	$1.59
Production costs, including taxes, per equivalent Mcf:			
Lease operating costs	$.93	$1.00	$.87
Gathering and transportation	.32	.30	.26
Production and property taxes	.39	.66	.48
	$1.64	$1.96	$1.61

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

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

Partially offsetting these decreases were:

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

2008 compared to 2007 The natural gas and oil production business experienced a decrease in earnings of $20.2 million (14 percent) due to:

- A noncash write-down of natural gas and oil properties of $84.2 million (after tax), as previously discussed
- Higher depreciation, depletion and amortization expense of $26.6 million (after tax), due to higher depletion rates and increased production
- Higher production taxes of $11.1 million (after tax), primarily due to higher average prices and increased production
- Increased lease operating costs of $9.3 million (after tax), including the East Texas properties acquired in early 2008

Partially offsetting these decreases were:

- Higher average realized natural gas prices of 24 percent
- Higher average realized oil prices of 38 percent
- Increased oil production of 19 percent, largely related to drilling activity in the Bakken area and Paradox Basin as well as production from the East Texas properties
- Increased natural gas production of 4 percent, primarily related to the acquisition of the East Texas properties, as previously discussed

Construction Materials and Contracting

Years ended December 31,	2009	2008	2007
	(Dollars in millions)		
Operating revenues	$1,515.1	$1,640.7	$1,761.5
Operating expenses:			
Operation and maintenance	1,292.0	1,437.9	1,483.5
Depreciation, depletion and amortization	93.6	100.9	95.8
Taxes, other than income	36.2	39.1	43.6
	1,421.8	1,577.9	1,622.9
Operating income	93.3	62.8	138.6
Earnings	$47.1	$30.2	$77.0
Sales (000's):			
Aggregates (tons)	23,995	31,107	36,912
Asphalt (tons)	6,360	5,846	7,062
Ready-mixed concrete (cubic yards)	3,042	3,729	4,085

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

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

Partially offsetting the increases were:

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

2008 compared to 2007 Earnings at the construction materials and contracting business decreased $46.8 million (61 percent) due to decreased construction workloads, margins and product volumes that were significantly lower as a result of the economic downturn, primarily as it relates to the residential market, as well as higher diesel fuel costs at existing operations, which had a combined negative effect on earnings of $53.0 million (after tax). Partially offsetting this decrease were earnings from companies acquired since the comparable prior period, which contributed approximately 8 percent of earnings for 2008.

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,	2009	2008	2007
		(In millions)	
Other:			
Operating revenues	$9.5	$10.5	$10.0
Operation and maintenance	8.1	5.9	15.9
Depreciation, depletion and amortization	1.3	1.3	1.2
Taxes, other than income	.3	.4	.2
Intersegment transactions:			
Operating revenues	$183.6	$394.1	$315.1
Purchased natural gas sold	156.7	365.7	286.8
Operation and maintenance	26.9	28.4	28.3

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 2010, diluted, are projected in the range of $1.10 to $1.35.

- The Company expects the percentage of 2010 earnings per common share by quarter to be in the following approximate ranges:

  – First quarter – 15 percent to 20 percent

  – Second quarter – 20 percent to 25 percent

  – Third quarter – 30 percent to 35 percent

  – Fourth quarter – 25 percent to 30 percent

- 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

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

- The Company is pursuing expansion opportunities.

– In April 2009, the Company purchased a 25 MW ownership interest in the Wygen III power generation facility which is under construction near Gillette, Wyoming. This rate-based generation will replace a portion of the purchased power for the Wyoming system. The plant is expected to be online during the second quarter of 2010. In August 2009, Montana-Dakota filed an application with the WYPSC for an electric rate increase, as discussed in Item 8 – Note 18.

– The Company is developing additional wind generation, including a 19.5 MW wind generation facility in southwest North Dakota and a 10.5 MW expansion of the Diamond Willow wind facility near Baker, Montana. Both projects are expected to be commercial midyear 2010.

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

- The Company is reviewing opportunities associated with the potential development of high voltage transmission lines targeted towards delivery of renewable energy from the wind rich regions that lie within its traditional electric service territory to major metropolitan areas.

Natural gas distribution

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

Construction services

- The Company anticipates margins in 2010 to be lower than 2009 levels.

- The Company is aggressively pursuing expansion in high voltage transmission construction, renewable resource construction and military installation services. The Company was recently awarded the engineering, procurement and construction contract to build the 214-mile Montana Alberta Tie Line between Lethbridge, Alberta and Great Falls, Montana.

- The Company continues to focus on costs and efficiencies to enhance margins. With its highly skilled technical workforce, this group is prepared to take advantage of government stimulus spending on transmission infrastructure.

- Work backlog as of December 31, 2009, was approximately $383 million, compared to $604 million at December 31, 2008. The December 31, 2009, backlog includes the new Montana Alberta Tie Line project, and excludes $182 million related to the Fontainebleau project, which is proceeding through the bankruptcy process.

Pipeline and energy services

- An incremental expansion to the Grasslands Pipeline of 75,000 Mcf per day went into service August 31, 2009. The firm capacity of the Grasslands Pipeline is at its ultimate full capacity of 213,000 Mcf per day.

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

- The Company has natural gas storage fields, including the largest storage field in North America located near Baker, Montana. Total working gas storage capacity is 193 Bcf for its three storage fields. The Company is pursuing a project to increase its firm deliverability and related transportation capacity from the Baker Storage field with a targeted in-service date in 2012.

Natural gas and oil production

- The Company expects to spend approximately $375 million in capital expenditures for 2010 for further exploitation of its existing properties, exploratory drilling and acquisitions of properties. This includes approximately $150 million for new growth opportunities, including acquisitions.

- The Company is also actively pursuing other potential exploratory and reserve acquisitions, which are not included in the current forecast.

- With the reduced 2009 capital expenditures and the forecasted 2010 capital expenditures, the Company expects its 2010 combined natural gas and oil production to be approximately equal to 2009 levels. The 2010 production forecast includes 3.5 Bcfe to 4 Bcfe related to growth opportunities.

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

Index*	Price Per Mcf
Ventura	$5.00 to $5.50
NYMEX	$5.25 to $5.75
CIG	$4.75 to $5.25

* 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.

- Earnings guidance reflects estimated NYMEX crude oil prices for February through December in the range of $70 to $75 per barrel.

- For 2010, the Company has hedged 45 percent to 50 percent of both its estimated natural gas and oil production. For 2011, the Company has hedged 10 percent to 15 percent of both its estimated natural gas and oil production. For 2012, the Company has hedged 5 percent to 10 percent of its estimated natural gas production. The hedges that are in place as of January 29, 2010, are summarized in the following chart:

Commodity	Type	Index*	Period Outstanding	Forward Notional Volume (MMBtu/Bbl)	Price (Per MMBtu/Bbl)
Natural Gas	Swap	HSC	1/10 - 12/10	1,606,000	$8.08
Natural Gas	Swap	NYMEX	1/10 - 12/10	3,650,000	$6.18
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.40
Natural Gas	Collar	NYMEX	1/10 - 12/10	1,825,000	$5.63-$6.00
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$5.855
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.045
Natural Gas	Swap	NYMEX	1/10 - 12/10	1,825,000	$6.045
Natural Gas	Swap	CIG	1/10 - 12/10	3,650,000	$5.03
Natural Gas	Swap	HSC	1/10 - 10/10	608,000	$5.57
Natural Gas	Swap	NYMEX	1/10 - 10/10	2,432,000	$5.645
Natural Gas	Swap	Ventura	1/10 - 12/10	1,825,000	$5.95
Natural Gas	Swap	NYMEX	4/10 - 12/10	3,025,000	$5.54
Natural Gas	Collar	NYMEX	1/10 - 3/11	2,275,000	$5.62-$6.50
Natural Gas	Swap	HSC	1/11 - 12/11	1,350,500	$8.00
Natural Gas	Swap	NYMEX	1/11 - 12/11	4,015,000	$6.1027
Natural Gas	Swap	NYMEX	1/12 - 12/12	3,477,000	$6.27
Crude Oil	Collar	NYMEX	1/10 - 12/10	365,000	$60.00-$75.00
Crude Oil	Swap	NYMEX	1/10 - 12/10	365,000	$73.20
Crude Oil	Collar	NYMEX	1/10 - 12/10	365,000	$70.00-$86.00
Crude Oil	Swap	NYMEX	1/10 - 12/10	365,000	$83.05
Crude Oil	Collar	NYMEX	1/11 - 12/11	547,500	$80.00-$94.00
Natural Gas	Basis			3,650,000	$0.25

		NYMEX to Ventura	1/10 - 12/10		
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	912,500	$0.245
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	4,562,500	$0.25
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	1,825,000	$0.225
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	912,500	$0.23
Natural Gas	Basis	NYMEX to Ventura	1/10 - 12/10	2,737,500	$0.23
Natural Gas	Basis	NYMEX to Ventura	1/11 - 3/11	450,000	$0.135

* Ventura is an index pricing point related to Northern Natural Gas Co.'s system; CIG is an index pricing point related to Colorado Interstate Gas Co.'s system; HSC is the Houston Ship Channel hub in southeast Texas which connects to several pipelines.

Construction materials and contracting

- Most of the markets served by construction materials are seeing positive impacts related to the federal stimulus spending.

- The Company is well positioned to take advantage of government stimulus spending on transportation infrastructure particularly in the asphalt paving and liquid asphalt oil product lines. Federal transportation stimulus of $7.9 billion was directed to states where the Company operates. Of that amount, 21 percent was spent in 2009, the remainder to be spent over the next two years, with 82 percent already obligated to specific projects by the various states.

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

- The Company has a strong emphasis on operational efficiencies and cost reduction.

- Liquid asphalt margins are expected to be lower in 2010 than the record levels experienced in 2009.

- Work backlog as of December 31, 2009, was approximately $459 million, compared to $453 million at December 31, 2008. Although public project margins tend to be somewhat lower than private construction-related work, the Company anticipates significant contributions to revenue from public works volume. Ninety-four percent of its year-end backlog is related to public works projects compared to 80 percent at December 31, 2008.

- As the country's 8th largest aggregate producer, the Company will continue to strategically manage its 1.1 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

New Accounting Standards
For information regarding new accounting standards, see Item 8 – Note 1, which is incorporated 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 purchase method of accounting; natural gas and oil reserves; aggregate reserves; property depreciable lives; tax provisions; uncollectible accounts; environmental and other loss contingencies; accumulated provision for revenues subject to refund; costs on construction contracts; unbilled revenues; actuarially determined benefit costs; asset retirement obligations; the valuation of stock-based compensation; and the fair value of derivative instruments. The Company's critical accounting policies are subject to judgments and uncertainties that affect the application of such policies. As discussed below, the Company's financial position or results of operations may be materially different when reported under different conditions or when using different assumptions in the application of such policies.

As additional information becomes available, or actual amounts are determinable, the recorded estimates are revised. Consequently, operating results can be affected by revisions to prior accounting estimates. The following critical accounting policies involve significant judgments and estimates.

Impairment of long-lived assets and intangibles
The Company reviews the carrying values of its long-lived assets and intangibles, excluding natural gas and oil properties, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and annually for goodwill. Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing an estimate of undiscounted future cash flows attributable to the assets compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In the case of goodwill, the first step, used to identify a potential impairment, compares the fair value of the reporting unit using discounted cash flows, with its carrying amount, including goodwill. The second step, used to measure the amount of the impairment loss if step one indicates a potential impairment, compares the implied fair value of the reporting unit goodwill with the carrying amount of goodwill.

Fair value is the amount at which the asset could be bought or sold in a current transaction between market participants. The Company uses critical estimates and assumptions when testing assets for impairment, including present value techniques based on estimates of cash flows, quoted market prices or valuations by third parties, or multiples of earnings or revenue performance measures. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

There is risk involved when determining the fair value of assets, tangible and intangible, as there may be unforeseen events and changes in circumstances and market conditions and changes in estimates of future cash flows.

The Company believes its estimates used in calculating the fair value of long-lived assets, including goodwill and identifiable intangibles, are reasonable based on the information that is known when the estimates are made.

Natural gas and oil properties
The Company uses the full-cost method of accounting for its natural gas and oil production activities. Capitalized costs are subject to a “ceiling test” that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties 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.

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.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The recognition of revenue in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of revenue. Critical estimates related to the recognition of revenue include the accumulated provision for revenues subject to refund and costs on construction contracts under the percentage-of-completion method.

Estimates for revenues subject to refund are established initially for each regulatory rate proceeding and are subject to change depending on the applicable regulatory agency's (Agency) approval of final rates. These estimates are based on the Company's analysis of its as-filed application compared to previous Agency decisions in prior rate filings by the Company and other regulated companies. The Company periodically reviews the status of its outstanding regulatory proceedings and liability assumptions and may from time to time change its liability estimates subject to known developments as the regulatory proceedings move through the regulatory review process. The accuracy of the estimates is ultimately determined when the Agency issues its final ruling on each regulatory proceeding for which revenues were subject to refund. Estimates have changed from time to time as additional information has become available as to what the ultimate outcome may be and will likely continue to change in the future as new information becomes available on each outstanding regulatory proceeding that is subject to refund.

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. This method depends largely on the ability to make reasonably dependable estimates related to the extent of progress toward completion of the contract, contract revenues and contract costs. Inasmuch as contract prices are generally set before the work is performed, the estimates pertaining to every project could contain significant unknown risks such as volatile labor, material and fuel costs, weather delays, adverse project site conditions, unforeseen actions by regulatory agencies, performance by subcontractors, job management and relations with project owners.

Several factors are evaluated in determining the bid price for contract work. These include, but are not limited to, the complexities of the job, past history performing similar types of work, seasonal weather patterns, competition and market conditions, job site conditions, work force safety, reputation of the project owner, availability of labor, materials and fuel, project location and project completion dates. As a project commences, estimates are continually monitored and revised as information becomes available and actual costs and conditions surrounding the job become known.

The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job.

Purchase accounting
The Company accounts for its acquisitions under the purchase method of accounting and, accordingly, the acquired assets and liabilities assumed are recorded at their respective fair values. The excess of the purchase price over the fair value of the assets acquired and liabilities assumed is recorded as goodwill. The recorded values of assets and liabilities are based in part on third-party estimates and valuations when available. The remaining values are based on management's judgments and estimates, and, accordingly, the Company's financial position or results of operations may be affected by changes in estimates and judgments.

Acquired assets and liabilities assumed by the Company that are subject to critical estimates include property, plant and equipment and intangibles.

The fair value of owned aggregate reserves is determined using qualified internal personnel as well as geologists. Reserve estimates are calculated based on the best available data. This data is collected from drill holes and other subsurface investigations as well as investigations of surface features such as mine highwalls and other exposures of the aggregate reserves. Mine plans, production history and geologic data are also used to estimate reserve quantities. Value is assigned to the aggregate reserves based on a review of market royalty rates, expected cash flows and the number of years of aggregate reserves at owned aggregate sites.

The fair value of property, plant and equipment is based on a valuation performed either by qualified internal personnel and/or outside appraisers. Fair values assigned to plant and equipment are based on several factors, including the age and condition of the equipment, maintenance records of the equipment and auction values for equipment with similar characteristics at the time of purchase.

The fair value of leasehold rights is based on estimates including royalty rates, lease terms and other discernible factors for acquired leasehold rights, and estimated cash flows.

While the allocation of the purchase price of an acquisition is subject to a considerable degree of judgment and uncertainty, the Company does not expect the estimates to vary significantly once an acquisition has been completed. The Company believes its estimates have been reasonable in the past as there have been no significant valuation adjustments subsequent to the final allocation of the purchase price to the acquired assets and liabilities. In addition, goodwill impairment testing is performed annually.

Asset retirement obligations
Entities are required to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. The Company has recorded obligations related to the plugging and abandonment of natural gas and oil wells, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution and transmission facilities and buildings, and certain other obligations associated with leased properties.

The liability for future asset retirement obligations bears the risk of change as many factors go into the development of the estimate of these obligations and the likelihood that over time these factors can and will change. Factors used in the estimation of future asset retirement obligations include estimates of current retirement costs, future inflation factors, life of the asset and discount rates. These factors determine both a present value of the retirement liability and the accretion to the retirement liability in subsequent years.

Long-lived assets are reviewed to determine if a legal retirement obligation exists. If a legal retirement obligation exists, a determination of the liability is made if a reasonable estimate of the present value of the obligation can be made. The present value of the retirement obligation is calculated by inflating current estimated retirement costs of the long-lived asset over its expected life to determine the expected future cost and then discounting the expected future cost back to the present value using a discount rate equal to the credit-adjusted risk-free interest rate in effect when the liability was initially recognized.

These estimates and assumptions are subject to a number of variables and are expected to change in the future. Estimates and assumptions will change as the estimated useful lives of the assets change, the current estimated retirement costs change, new legal retirement obligations occur and/or as existing legal asset retirement obligations, for which a reasonable estimate of fair value could not initially be made because of the range of time over which the Company may settle the obligation is unknown or cannot be estimated, become less uncertain and a reasonable estimate of the future liability can be made.

Pension and other postretirement benefits
The Company has noncontributory defined benefit pension plans and other postretirement benefit plans for certain eligible employees. Various actuarial assumptions are used in calculating the benefit expense (income) and liability (asset) related to these plans. Costs of providing pension and other postretirement benefits bear the risk of change, as they are dependent upon numerous factors based on assumptions of future conditions.

The Company makes various assumptions when determining plan costs, including the current discount rates and the expected long-term return on plan assets, the rate of compensation increases and healthcare cost trend rates. In selecting the expected long-term return on plan assets, which is considered to be one of the key variables in determining benefit expense or income, the Company considers 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 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.

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

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

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

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

Liquidity and Capital Commitments

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

Cash flows provided by operating activities in 2008 increased $223.0 million from the comparable prior period, due to:

- Higher income from continuing operations before depreciation, depletion and amortization and before the after-tax noncash write-down of natural gas and oil properties
    - Absence of cash flows used related to discontinued operations in 2007 of $71.4 million

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

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

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

Cash flows used in investing activities in 2008 increased $765.1 million from the comparable prior period due to:

- Absence of cash flows provided by discontinued operations in 2007 of $548.2 million, primarily the result of the sale of the domestic independent power production assets in the third quarter of 2007
- Increased ongoing capital expenditures of $188.2 million, largely at the natural gas and oil production business
- Higher cash used in connection with acquisitions, net of cash acquired, of $185.1 million, largely due to the acquisition of Intermountain and natural gas and oil producing properties in East Texas in 2008, partially offset by the absence of the 2007 acquisition of Cascade

Partially offsetting the increase in cash flows used in investing activities were higher proceeds from investments of $85.8 million in 2008, as well as the absence of cash used for investments of $67.1 million in 2007.

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

Cash flows provided by financing activities in 2008 increased $456.2 million from the comparable prior period, primarily due to higher issuance of long-term debt of $333.7 million as well as higher net short-term borrowings of $101.7 million, largely related to higher ongoing capital expenditures and acquisitions.

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, 2009, the Pension Plans' accumulated benefit obligations exceeded these plans' assets by approximately $85.0 million. Pretax pension expense reflected in the years ended December 31, 2009, 2008 and 2007, was $8.2 million,

$4.6 million and $6.5 million, respectively. The Company's pension expense is currently projected to be approximately $3.5 million to $4.5 million in 2010. Funding for the Pension Plans is actuarially determined. The minimum required contributions for 2009, 2008 and 2007 were approximately $7.3 million, $6.8 million and $1.8 million, respectively. For further information on the Company's Pension Plans, see Item 8 – Note 16.

Capital expenditures

The Company's capital expenditures for 2007 through 2009 and as anticipated for 2010 through 2012 are summarized in the following table, which also includes the Company's capital needs for the retirement of maturing long-term debt.

	Actual			Estimated*		
	2007	2008	2009	2010	2011	2012
			(In millions)			
Capital expenditures:						
Electric	$91	$73	$115	$105	$72	$100
Natural gas distribution	500	398	44	76	60	59
Construction services	18	24	13	13	11	11
Pipeline and energy services	39	43	70	15	28	149
Natural gas and oil production	284	711	183	375 **	359	321
Construction materials and contracting	190	128	27	37	52	62
Other	2	1	3	1	1	1
Net proceeds from sale or disposition of property	(25)	(87)	(27)	(4)	(7)	(1)
Net capital expenditures before discontinued operations	1,099	1,291	428	618	576	702
Discontinued operations	(548)	—	—	—	—	—
Net capital expenditures	551	1,291	428	618	576	702
Retirement of long-term debt	232	201	293	13	72	136
	$783	$1,492	$721	$631	$648	$838

*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.

** Includes approximately $150 million for new growth opportunities, including potential acquisitions.

Capital expenditures for 2009, 2008 and 2007 in the preceding table include noncash transactions, including the issuance of the Company's equity securities, in connection with acquisitions and the outstanding indebtedness related to the 2008 Intermountain acquisition and the 2007 Cascade acquisition. The net noncash transactions were immaterial in 2009, $97.6 million in 2008 and $217.3 million in 2007.

In 2009, the Company acquired a pipeline and energy services business in Montana. 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 2009 capital expenditures, including those for the previously mentioned acquisitions and retirements of long-term debt, were met from internal sources and the issuance of long-term debt and the Company's equity securities. Estimated capital expenditures for the years 2010 through 2012 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, exploratory drilling and acquisitions at the natural gas and oil production segment
- Power generation opportunities, including certain costs for additional electric generating capacity
- 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 2010 through 2012 will be met from various sources, including internally generated funds; the Company's credit facilities, as described below; and through the issuance of long-term debt and the Company's equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed 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, 2009. 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, 2009:

Company	Facility	Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date	
(Dollars in millions)									
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$125.0		$—	(b)	$—		6/21/11	
MDU Energy Capital, LLC	Master shelf agreement	$175.0		$165.0		$—		8/14/10	(c)
Cascade Natural Gas Corporation	Revolving credit agreement	$50.0	(d)	$—		$1.9	(e)	12/28/12	(f)
Intermountain Gas Company	Revolving credit agreement	$65.0	(g)	$10.3		$—		8/31/10	
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (h)	$400.0		$—	(b)	$26.4	(e)	12/13/12	
Williston Basin Interstate Pipeline Company	Uncommitted long-term private shelf agreement	$125.0		$87.5		$—		12/23/10	(i)

(a) The $125 million commercial paper program is supported by a revolving credit agreement with various banks totaling $125 million (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $150 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Or such time as the agreement is terminated by either of the parties thereto.
(d) Certain provisions allow for increased borrowings, up to a maximum of $75 million.
(e) The outstanding letters of credit, as discussed in Item 8 – Note 19, reduce amounts available under the credit agreement.
(f) Provisions allow for an extension of up to two years upon consent of the banks.
(g) Certain provisions allow for increased borrowings, up to a maximum of $70 million.
(h) 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.
(i) Certain provisions allow for an extension to December 23, 2011.

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

The following includes information related to the above table.

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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 further downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

Prior to the maturity of the credit agreement, the Company expects that it will negotiate the extension or replacement of this agreement. If the Company is unable to successfully negotiate an extension of, or replacement for, the credit agreement, or if the fees on this facility become too expensive, which the Company does not currently anticipate, the Company would seek alternative funding.

In November 2009, the Company completed a defeasance of its outstanding 8.60% Secured Medium-Term Notes under the Mortgage and the Mortgage was discharged. For more information, see Item 8 – Note 9.

The Company's coverage of fixed charges including preferred stock dividends was 5.3 times for the 12 months ended December 31, 2008. Due to the $384.4 million after-tax noncash write-down of natural gas and oil properties in the first quarter of 2009, earnings were insufficient by $228.7 million to cover fixed charges for the 12 months ended December 31, 2009. If the $384.4 million after-tax noncash write-down is excluded, the coverage of fixed charges including preferred stock dividends would have been 4.6 times for the 12 months ended December 31, 2009. Common stockholders' equity as a percent of total capitalization was 63 percent and 61 percent at December 31, 2009 and 2008, respectively.

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.

In September 2008, the Company entered into a Sales Agency Financing Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 5 million shares of the Company's common stock. The common stock may be offered for sale, from time to time, in accordance with the terms and conditions of the agreement, which terminates on May 28, 2011. Proceeds from the sale of shares of common stock under the agreement have been and are expected to be used for corporate development purposes and other general corporate purposes. The Company issued approximately 600,000 shares of stock during the fourth quarter under the Sales Agency Financing Agreement, resulting in net proceeds of $12.2 million, and has issued a total of approximately 3.2 million shares of stock under the Sales Agency Financing Agreement through December 31, 2009, resulting in total net proceeds of $63.1 million.

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

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

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

Off balance sheet arrangements

In connection with the sale of MPX in June 2005 to Petrobras, an indirect wholly owned subsidiary of the Company has agreed to indemnify Petrobras for 49 percent of any losses that Petrobras may incur from certain contingent liabilities specified in the purchase agreement. For more information, see Item 8 – Note 19.

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

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on long-term debt, operating leases, purchase commitments and uncertain tax positions, see Item 8 – Notes 9, 14 and 19. At December 31, 2009, the Company's commitments under these obligations were as follows:

	2010	2011	2012	2013	2014	Thereafter	Total
				(In millions)			
Long-term debt	$12.6	$72.3	$136.3	$258.8	$9.1	$1,010.2	$1,499.3
Estimated interest payments*	91.9	87.8	84.0				