MDU RESOURCES GROUP INC

FORM 10-K
(Annual Report)

Filed 02/24/17 for the Period Ending 12/31/16

Address	1200 WEST CENTURY AVENUE BISMARCK, ND 58503
Telephone	701-530-1059
CIK	0000067716
Symbol	MDU
SIC Code	1400 - Mining & Quarrying of Nonmetallic Minerals (No Fuels)
Industry	Multiline Utilities
Sector	Utilities
Fiscal Year	12/31

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

FORM 10-K

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2016

OR

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____________ to ______________
Commission file number 1-3480

MDU RESOURCES GROUP, INC.

(Exact name of registrant as specified in its charter)

Delaware	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 ☐ No ☒ .

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 ☐ No ☒ .

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 ☒ No ☐ .

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 ☒ No ☐ .

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. ☐

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 ☒	Accelerated filer ☐
Non-accelerated filer ☐ (Do not check if a smaller reporting company)	Smaller reporting company ☐

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

State the aggregate market value of the voting common stock held by nonaffiliates of the registrant as of June 30, 2016 : $4,687,305,024 .

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of February 16, 2017 : 195,304,376 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Relevant portions of the registrant's 2017 Proxy Statement are incorporated by reference in Part III, Items 10, 11, 12, 13 and 14 of this Report.

Contents

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

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
BART	Best available retrofit technology
Bcf	Billion cubic feet
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
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's Consolidated EBITDA	Centennial's consolidated net income from continuing operations plus the related interest expense, taxes, depreciation, depletion, amortization of intangibles and any non-cash charge relating to asset impairment for the preceding 12-month period
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.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
D.C. Circuit Court	United States Court of Appeals for the District of Columbia Circuit
dk	Decatherm
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
ERISA	Employee Retirement Income Security Act of 1974
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 (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
GHG	Greenhouse gas
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
GVTC	Generation Verification Test Capacity
IBEW	International Brotherhood of Electrical Workers

Definitions

ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Item 8	Financial Statements and Supplementary Data
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
kW	Kilowatts
kWh	Kilowatt-hour
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
MD&A	Management's Discussion and Analysis of Financial Condition and Results of Operations
Mdk	Thousand dk
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
MEPP	Multiemployer pension plan
MISO	Midcontinent Independent System Operator, Inc.
MMBOE	Millions of BOE
MMBtu	Million Btu
MMcf	Million cubic feet
MMdk	Million dk
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana DEQ	Montana Department of Environmental Quality
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MPPAA	Multiemployer Pension Plan Amendments Act of 1980
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NGL	Natural gas liquids
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
PCBs	Polychlorinated biphenyls
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream previously held a 50 percent non-operating ownership interest)
Proxy Statement	Company's 2017 Proxy Statement
PRP	Potentially Responsible Party
PUD	Proved undeveloped
RCRA	Resource Conservation and Recovery Act
ROD	Record of Decision
RP	Rehabilitation plan
SDPUC	South Dakota Public Utilities Commission
SEC	United States Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas 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
South Dakota DENR	South Dakota Department of Environment and Natural Resources
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
Tesoro	Tesoro Refining & Marketing Company LLC
Tesoro Logistics	QEP Field Services, LLC doing business as Tesoro Logistics Rockies LLC
Thurston County Superior Court	State of Washington Thurston County Superior Court
UA	United Association of Journeyman and Apprentices of the Plumbing and Pipefitting Industry of the United States and Canada
United States District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
United States Supreme Court	Supreme Court of the United States
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission
ZRCs	Zonal resource credits - a MW of demand equivalent assigned to generators by MISO for meeting system reliability requirements

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 regulated energy delivery and construction materials and services business, 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, Great Plains, Cascade and Intermountain comprise the natural gas distribution segment. Montana-Dakota also comprises the electric segment.

The Company, through its wholly owned subsidiary, Centennial, owns WBI Holdings, Knife River, MDU Construction Services, Centennial Resources and Centennial Capital. WBI Holdings is comprised of the pipeline and midstream segment and Fidelity, formerly the Company's exploration and production business. Knife River is the construction materials and contracting segment, MDU Construction Services is the construction services segment, and Centennial Resources and Centennial Capital are both reflected in the Other category.

In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining and exited that line of business. Therefore, the results of Dakota Prairie Refining are reflected in discontinued operations, other than certain general and administrative costs and interest expense which are reflected in the Other category.

In the second quarter of 2015, the Company announced its plan to market Fidelity and exit that line of business. The Company completed the sale of its oil and natural gas assets. Therefore, the results of Fidelity are reflected in discontinued operations, other than certain general and administrative costs and interest expense which are reflected in the Other category.

For more information on the Company's business segments and discontinued operations, see Item 8 - Notes 2 and 13 .

As of December 31, 2016 , the Company had 9,598 employees with 138 employed at MDU Resources Group, Inc., 1,030 at Montana-Dakota, 35 at Great Plains, 342 at Cascade, 236 at Intermountain, 342 at WBI Holdings, 3,099 at Knife River and 4,376 at MDU Construction Services. The number of employees at certain Company operations fluctuates during the year depending upon the number and size of construction projects. The Company considers its relations with employees to be satisfactory.

The following information regarding the number of employees represented by labor contracts is as of December 31, 2016 .

At Montana-Dakota and WBI Energy Transmission, 359 and 68 employees, respectively, are represented by the IBEW. Labor contracts with such employees are in effect through April 30, 2018, and March 31, 2018, respectively.

At Cascade, 195 employees are represented by the ICWU. The labor contract with the field operations group is effective through March 31, 2018.

At Intermountain, 127 employees are represented by the UA. Labor contracts with such employees are in effect through September 30, 2019.

Knife River operates under 43 labor contracts that represent 505 of its construction materials employees. Knife River is in negotiations on seven of its labor contracts.

MDU Construction Services has 142 labor contracts representing the majority of its employees. MDU Construction Services is in negotiations on five of its labor contracts.

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 13 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 17 . There are no pending CERCLA actions for any of the Company's properties, other than the Portland, Oregon, Harbor Superfund Site and the Bremerton Gasworks 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, and operations of equipment and fleet vehicles. GHG emissions also result from customer use of natural gas for heating and other uses. As interest in reductions in GHG emissions has grown, the Company has developed renewable generation with lower or no GHG emissions. Governmental legislative and regulatory initiatives regarding environmental and energy policy are continuously evolving and could negatively impact the Company's operations and financial results. Until legislation and regulation are finalized, the impact of these measures cannot be accurately predicted. The Company will continue to monitor legislative and regulatory activity related to environmental and energy policy initiatives. Disclosure regarding specific environmental matters applicable to each of the Company's businesses is set forth under each business description later. In addition, for a discussion of the Company's risks related to environmental laws and regulations, see Item 1A - Risk Factors.

This annual report on Form 10-K, the Company's quarterly reports on Form 10-Q and 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 142,948 residential, commercial, industrial and municipal customers in 178 communities and adjacent rural areas as of December 31, 2016 . For more information on the customer classes served, see the table below. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 13 electric generating facilities and three small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,100 and 4,800 miles of transmission and distribution lines, respectively, and 74 transmission and 316 distribution substations. Montana-Dakota has obtained and holds, or is in the process of renewing, valid and existing franchises authorizing it to conduct its electric operations in all of the municipalities it serves where such franchises are required. Montana-Dakota intends to protect its service area and seek renewal of all expiring franchises. At December 31, 2016 , Montana-Dakota's net electric plant investment was $1.3 billion, and the rate base was $1.0 billion.

Montana-Dakota's customers served and revenues by class are as follows:

	2016		2015		2014	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**118,483**	**$ 117,014**	118,413	$ 107,767	115,164	$ 109,279
Commercial	**22,693**	**135,390**	22,423	121,463	21,890	118,026
Industrial	**244**	**31,913**	240	32,786	245	30,457
Other	**1,528**	**7,580**	1,511	6,791	1,497	6,750
	142,948	**$ 291,897**	142,587	$ 268,807	138,796	$ 264,512

The percentage of Montana-Dakota's retail electric utility operating revenues by jurisdiction is as follows:

	2016	2015	2014
North Dakota	**68%**	65%	64%
Montana	**19%**	21%	21%
Wyoming	**8%**	9%	10%
South Dakota	**5%**	5%	5%

Retail electric rates, service, accounting and certain security issuances are subject to regulation by the NDPSC, MTPSC, SDPUC and WYPSC. The interstate transmission and wholesale electric power operations of Montana-Dakota also are subject to regulation by the FERC under provisions of the Federal Power Act, as are interconnections with other utilities and power generators, the issuance of securities, accounting and other matters.

Through MISO, Montana-Dakota has access to wholesale energy, ancillary services and capacity markets for its interconnected system. MISO is a regional transmission organization responsible for operational control of the transmission systems of its members. MISO provides security center operations, tariff administration and operates day-ahead and real-time energy markets, ancillary services and capacity markets. As a member of MISO, Montana-Dakota's generation is sold into the MISO energy market and its energy needs are purchased from that market.

System Supply, System Demand and Competition Through an interconnected electric system, Montana-Dakota serves markets in portions of western North Dakota, including Bismarck, Mandan, Dickinson, Williston and Watford City; eastern Montana, including Sidney, Glendive and Miles City; and northern South Dakota, including Mobridge. The maximum electric peak demand experienced to date attributable to Montana-Dakota's sales to retail customers on the interconnected system was 611,542 kW in August 2015. Montana-Dakota's latest forecast for its interconnected system indicates that its annual peak will continue to occur during the summer and the sales growth rate through 2021 will approximate two percent annually. The interconnected system consists of 12 electric generating facilities and three small portable diesel generators, which have an aggregate nameplate rating attributable to Montana-Dakota's interest of 704,143 kW and total net ZRCs of 521.0 in 2016 . ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet planning reserve margin requirements within MISO. For 2016 , Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 559.7 . Montana-Dakota's planning reserve margin requirement within MISO was 559.7 for 2016 . Montana-Dakota's interconnected system electric generating capability includes five steam-turbine generating units at four facilities using coal for fuel, three combustion turbine peaking stations, three wind electric generating facilities, two reciprocating internal combustion engines at one facility, a heat recovery electric generating facility and three small portable diesel generators.

In June 2016, Montana-Dakota and a partner began building a 345-kilovolt transmission line within the footprint of MISO from Ellendale, North Dakota, to Big Stone City, South Dakota, a distance of about 160 miles, which will facilitate public policy goals and objectives, including delivery of renewable wind energy from North Dakota to eastern markets. The project has been approved as a MISO multivalue project. Approximately 97 percent of the necessary easements have been secured. The Company expects the project to be completed in 2019.

In December 2016, Montana-Dakota signed a 25-year agreement to purchase the power from a wind farm expansion in southwest North Dakota. The agreement also includes an option to buy the project at the close of construction. The expansion of the wind farm will boost the combined production at the wind farm to approximately 150 MW of renewable energy and will increase Montana-Dakota's nameplate generation portfolio from approximately 22 percent renewables to 27 percent. The original 107.5-MW wind farm includes 43 turbines; it was purchased by Montana-Dakota in December 2015. The expansion includes 13 to 16 turbines, depending on the turbine size selected. It is expected to be online in December 2018. Construction costs for the project are estimated to be $85 million. Additional energy will be purchased as needed, or if more economical, from the MISO market. In 2016 , Montana-Dakota purchased approximately 26 percent of its net kWh needs for its interconnected system through the MISO market.

Through the Sheridan System, Montana-Dakota serves Sheridan, Wyoming, and neighboring communities. The maximum peak demand experienced to date attributable to Montana-Dakota sales to retail customers on that system was approximately 61,501 kW in July 2012. Montana-Dakota has a power supply contract with Black Hills Power, Inc. to purchase up to 49,000 kW of capacity annually through December 31, 2023. Wygen III serves a portion of the needs of its Sheridan-area customers.

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

Generating Station	Type	Nameplate Rating (kW)	2016 ZRCs (a)	2016 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	80.6	615,730
Heskett	Steam	86,000	87.3	458,788
Heskett	Combustion Turbine	89,038	57.0	2,868
Glen Ullin	Heat Recovery	7,500	4.2	39,383
Cedar Hills	Wind	19,500	4.9	60,790
Diesel Units	Oil	5,475	3.8	9
Thunder Spirit	Wind	107,500	17.2	427,960
South Dakota:				
Big Stone (b)	Steam	94,111	99.7	440,834
Montana:				
Lewis & Clark	Steam	44,000	51.9	261,058
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	14.1	11,918
Glendive	Combustion Turbine	75,522	72.5	6,277
Miles City	Combustion Turbine	23,150	21.6	712
Diamond Willow	Wind	30,000	6.2	100,119
		704,143	521.0	2,426,446
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	200,317
		732,143	521.0	2,626,763

(a) Interconnected system only. MISO requires generators to obtain their summer capability through the GVTC. The GVTC is then converted to ZRCs by applying each generator's forced outage factor against its GVTC. Wind generator's ZRCs are calculated based on a wind capacity study performed annually by MISO. ZRCs are used to meet supply obligations within MISO.
(b) Reflects Montana-Dakota's ownership interest.

Virtually all of the current fuel requirements of the Heskett and Lewis & Clark stations are met with coal supplied by subsidiaries of Westmoreland Coal Company under contracts that expire in December 2021 and December 2017, respectively. 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 425,000 to 460,000 tons and 250,000 to 350,000 tons per contract year, respectively.

The owners of Coyote Station, including Montana-Dakota, have a contract with Coyote Creek for coal supply to the Coyote Station that expires December 2040. Montana-Dakota estimates the Coyote Station coal supply agreement to be approximately 2.5 million tons per contract year. For more information, see Item 8 - Note 17 .

The owners of Big Stone Station, including Montana-Dakota, have coal supply agreements, which meet a portion of the Big Stone Station's fuel requirements, for the purchase of 750,000 tons in 2017 from Alpha Coal Sales Co., LLC at contracted pricing. The remainder of the Big Stone Station fuel requirements will be secured through separate future contracts.

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

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

Years ended December 31,		**2016**		2015		2014
Average cost of coal per MMBtu	**$**	**1.89**	$	1.75	$	1.74
Average cost of coal per ton	**$**	**27.45**	$	25.41	$	25.11

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-2022. Future capacity that is needed to replace contracts and meet system growth requirements is expected to be met by constructing new generation resources, or acquiring additional capacity through power purchase contracts or the MISO capacity auction. For more information regarding potential power generation projects, see Item 7 - MD&A - Prospective Information - Electric and natural gas distribution.

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

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

Regulatory Matters and Revenues Subject to Refund In North Dakota, Montana-Dakota's results of operations reflect monthly increases or decreases in fuel and purchased power costs (including demand charges) and is deferring those electric fuel and purchased power costs that are greater or less than amounts presently being recovered through its existing rate schedules. In Montana, a monthly Fuel and Purchased Power Tracking Adjustment mechanism allows Montana-Dakota's results of operations to reflect 90 percent of the increases or decreases in fuel and purchased power costs (including demand charges) and Montana-Dakota is deferring 90 percent of costs that are greater or less than amounts presently being recovered through its existing rate schedules. A fuel adjustment clause contained in South Dakota jurisdictional electric rate schedules allows Montana-Dakota's results of operations to reflect monthly increases or decreases in fuel and purchased power costs (excluding demand charges). In Wyoming, an annual Electric Power Supply Cost Adjustment mechanism allows Montana-Dakota's results of operations to reflect increases or decreases in purchased power costs (including demand charges) related to power supply and Montana-Dakota is deferring costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments which are filed annually. As of March 1, 2017, Montana-Dakota's results of operations will reflect 95 percent of the increases or decreases from the base purchased power costs and in addition will also reflect 85 percent of the increases or decreases from the base coal price, which will also be recovered through the Electric Power Supply Cost Adjustment. For more information, see Item 8 - Note 4 .

In North Dakota, Montana-Dakota recovers in rates the costs associated with environmental upgrades at Big Stone Station and Lewis & Clark Station. Montana-Dakota will maintain a tracker account until all costs are recovered or until the associated costs are reflected in base rates as a part of a general rate case.

In North Dakota, Montana-Dakota has the ability to recover the costs associated with new generation through a rider mechanism. Montana-Dakota will utilize this rider mechanism for new generation until such time as the costs and investment are included in base rates. For the Thunder Spirit Wind project, Montana-Dakota implemented a renewable resource cost adjustment rider. Montana-Dakota also has in place in North Dakota a transmission tracker to recover transmission costs associated with MISO and the Southwest Power Pool, regional transmission systems serving Montana-Dakota, along with certain of the transmission investments not recovered through retail rates. The tracking mechanism has an annual true-up.

In South Dakota, Montana-Dakota recovers the South Dakota investment in the Thunder Spirit Wind project through an Infrastructure Rider tracking mechanism that is subject to an annual true-up. Montana-Dakota also has in place in South Dakota a transmission tracker to recover transmission costs associated with MISO and the Southwest Power Pool, regional transmission systems serving Montana-Dakota, along with certain of the transmission investments not recovered through retail rates. The tracking mechanism has an annual true-up.

For more information on regulatory matters, see Item 8 - Note 16 .

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

Montana-Dakota's electric generating facilities have Title V Operating Permits, under the Clean Air Act, issued by the states in which they operate. Each of these permits has a five-year life. Near the expiration of these permits, renewal applications are submitted. Permits continue in force beyond the expiration date, provided the application for renewal is submitted by the required date, usually six months prior to expiration. The Title V Operating Permit renewal application for Big Stone Station was submitted timely to the South Dakota DENR in November 2013. Big Stone Station continues to operate under conditions of the Title V Operating Permit issued by the South Dakota DENR in June 2009. It is expected that a final renewed permit will be issued in 2017 as the South Dakota DENR incorporates the completed BART air quality control system into the permit. Wygen III is allowed to operate under the facility's construction permit until the Title V Operating Permit is issued by the Wyoming Department of Environmental Quality. The Title V Operating Permit application for Wygen III was submitted timely in January 2011, with the permit expected to be issued in 2017. An application to modify the Title V Operating Permit for incorporation of two new natural gas-fired engines at Lewis & Clark Station was submitted to the Montana DEQ timely in December 2016, with a final permit expected to be issued in 2017. The Title V Operating Permit applications for the Miles City and Glendive stations were submitted timely in 2016 and final permits were issued by the Montana DEQ for each facility in August 2016 and July 2016, respectively.

State water discharge permits issued under the requirements of the Clean Water Act are maintained for power production facilities on the Yellowstone and Missouri rivers. These permits also have five-year lives. Montana-Dakota renews these permits as necessary prior to expiration. Other permits held by these facilities may include an initial siting permit, which is typically a one-time, preconstruction permit issued by the state; state permits to dispose of combustion by-products; state authorizations to withdraw water for operations; and Army Corps permits to construct water intake structures. Montana-Dakota's Army Corps permits grant one-time permission to construct and do not require renewal. Other permit terms vary and the permits are renewed as necessary.

Montana-Dakota's electric operations are conditionally exempt small-quantity hazardous waste generators and subject only to minimum regulation under the RCRA. Montana-Dakota routinely handles PCBs from its electric operations in accordance with federal requirements. PCB storage areas are registered with the EPA as required.

Montana-Dakota incurred $14.2 million of environmental capital expenditures in 2016 , mainly for ash management projects at Lewis & Clark Station and air emission control projects at Heskett Station and Coyote Station. Environmental capital expenditures are estimated to be $3.5 million, $9.0 million and $6.5 million in 2017 , 2018 and 2019 , respectively, for various environmental upgrades and improvements for air emission and water and coal ash management at power plants. Montana-Dakota's capital and operational expenditures could also be affected by future air emission regulations and coal ash management requirements, including the Clean Power Plan rule published by the EPA in October 2015. The Clean Power Plan requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. Montana-Dakota is evaluating the Clean Power Plan and has not included estimates for capital expenditures in 2017 through 2019 for potential compliance requirements. On February 9, 2016, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending disposition of the applicants' petition for review in the D.C. Circuit Court and disposition of the applicants' petition for a writ of certiorari if such a writ is sought.

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 922,408 residential, commercial and industrial customers in 335 communities and adjacent rural areas across eight states as of December 31, 2016 , and provide natural gas transportation services to certain customers on the Company's systems. For more information on the customer classes served, see the table below. These services are provided through distribution systems aggregating approximately 19,400 miles. The natural gas distribution operations have obtained and hold, or are in the process of renewing, valid and existing franchises authorizing them to conduct their natural gas operations in all of the municipalities they serve where such franchises are required. These operations intend to protect their service areas and seek renewal of all expiring franchises. At December 31, 2016 , the natural gas distribution operations' net natural gas distribution plant investment was $1.5 billion, and the rate base was $868 million.

The customers served and revenues by class for the natural gas distribution operations are as follows:

	2016		2015		2014	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**818,163**	**$ 429,828**	803,846	$ 455,301	791,870	$ 513,373
Commercial	**103,438**	**253,333**	101,688	277,022	100,288	324,203
Industrial	**807**	**23,337**	811	26,568	756	30,917
	922,408	**$ 706,498**	906,345	$ 758,891	892,914	$ 868,493

The percentage of the natural gas distribution operations' natural gas utility operating sales revenues by jurisdiction is as follows:

	2016	2015	2014
Idaho	**34%**	32%	29%
Washington	**26%**	26%	25%
North Dakota	**13%**	15%	16%
Montana	**8%**	8%	9%
Oregon	**8%**	8%	8%
South Dakota	**6%**	6%	7%
Minnesota	**3%**	3%	4%
Wyoming	**2%**	2%	2%

The natural gas distribution operations are subject to regulation by the IPUC, MNPUC, MTPSC, NDPSC, OPUC, SDPUC, WUTC and WYPSC regarding retail rates, service, accounting and certain security issuances.

System Supply, System Demand and Competition The natural gas distribution operations serve retail natural gas markets, consisting principally of residential and firm commercial space and water heating users, in portions of Idaho, including Boise, Nampa, Twin Falls, Pocatello and Idaho Falls; western Minnesota, including Fergus Falls, Marshall and Crookston; eastern Montana, including Billings, Glendive and Miles City; North Dakota, including Bismarck, Mandan, Dickinson, Wahpeton, Williston, Watford City, Minot and Jamestown; central and eastern Oregon, including Bend, Pendleton, Ontario and Baker City; western and north-central South Dakota, including Rapid City, Pierre, Spearfish and Mobridge; western, southeastern and south-central Washington, including Bellingham, Bremerton, Longview, Aberdeen, Wenatchee/Moses Lake, Mount Vernon, Tri-Cities, Walla Walla and Yakima; and northern Wyoming, including Sheridan and Lovell. 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. In addition to the residential and commercial sales, the utilities transport natural gas for larger commercial and industrial customers who purchase their own supply of natural gas.

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. 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 and various distribution transportation customers obtain their system requirements directly from producers, processors and marketers. The Company's purchased natural gas is supplied by a portfolio of contracts specifying market-based pricing and is transported under transportation agreements with WBI Energy Transmission, Northern Border Pipeline Company, Northwest Pipeline LLC, Northern Natural Gas, Gas Transmission Northwest LLC, Northwestern Energy, Viking Gas Transmission Company, Westcoast Energy Inc., Ruby Pipeline LLC, Foothills Pipe Lines Ltd. and NOVA Gas Transmission Ltd. The natural gas distribution operations have contracts for storage services to provide gas supply during the winter heating season and to meet peak day demand with various storage providers, including WBI Energy Transmission, Questar Pipeline Company, Northwest Pipeline LLC and Northern Natural Gas. In addition, certain of the operations have entered into natural gas supply management agreements with various parties. Demand for natural gas, which is a widely traded commodity, has historically been sensitive to seasonal heating and industrial load requirements as well as changes in market price. The natural gas distribution operations believe that, based on current and projected domestic and regional supplies of natural gas and the pipeline transmission network currently available through their suppliers and pipeline service providers, supplies are adequate to meet their system natural gas requirements for the next decade.

Regulatory Matters The natural gas distribution operations' retail natural gas rate schedules contain clauses permitting adjustments in rates based upon changes in natural gas commodity, transportation and storage costs. Current tariffs allow for recovery or refunds of under- or over-recovered gas costs through rate adjustments which are filed annually.

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

On December 28, 2015, the OPUC approved an extension of Cascade's decoupling mechanism until January 1, 2020, with an agreement that Cascade would initiate a review of the mechanism by September 30, 2019. Cascade also has an earnings sharing mechanism with respect to its Oregon jurisdictional operations as required by the OPUC.

On July 7, 2016, the WUTC approved a full decoupling mechanism where Cascade is allowed recovery of an average revenue per customer regardless of actual consumption. The mechanism also includes an earnings sharing component if Cascade earns beyond its authorized return. The decoupling mechanism will be reviewed following the end of 2019.

On December 22, 2016, the MNPUC approved a request by Great Plains to implement a full revenue decoupling mechanism pilot project. The decoupling mechanism will reflect the period October 1 through September 30 with the first adjustment to be billed to customers effective December 1 each year for the 3 year pilot project.

For more information on regulatory matters, see Item 8 - Note 16 .

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

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

The natural gas distribution operations did not incur any material environmental expenditures in 2016 . Except as to what may be ultimately determined with regard to the issues described in the following paragraph, the natural gas distribution operations do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2019 .

Montana-Dakota and Great Plains have ties to six historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Montana-Dakota is investigating one of these former manufactured gas plant sites and providing input on another site investigation conducted by a third party. To the extent not covered by insurance, Montana-Dakota will seek recovery in its natural gas rates charged to customers for any investigation and remediation costs incurred for these sites. Cascade has ties to nine historic manufactured gas plants as a successor corporation or through direct ownership of the plant. Cascade is involved in the investigation and remediation of three of these manufactured gas plants in Washington and Oregon. See Item 8 - Note 17 for a further discussion of these three manufactured gas plants. To the extent not covered by insurance, Cascade will seek recovery of investigation and remediation costs through its natural gas rates charged to customers.

Pipeline and Midstream

General WBI Energy owns and operates both regulated and nonregulated businesses. The regulated business of this segment, WBI Energy Transmission, owns and operates approximately 4,000 miles of transmission, gathering and storage lines in Montana, North Dakota, South Dakota and Wyoming. Three underground storage fields in Montana and Wyoming provide storage services to local distribution companies, industrial customers, natural gas marketers and others, and serve to enhance system reliability. Its system is strategically located near five natural gas producing basins, making natural gas supplies available to its transportation and storage customers. The system has 13 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. Under the Natural Gas Act, as amended, WBI Energy Transmission is subject to the jurisdiction of the FERC regarding certificate, rate, service and accounting matters, and at December 31, 2016 , its net plant investment was $388.0 million.

The nonregulated business of this segment owns and operates gathering facilities in Montana and Wyoming. In total, facilities include approximately 800 miles of operated field gathering lines, some of which interconnect with WBI Energy's regulated pipeline system. The nonregulated business provides natural gas gathering services and a variety of other energy-related services, including cathodic protection, contract compression operations, measurement services, and energy efficiency product sales and installation services to large end-users. In November 2016, the Company entered into an agreement to sell its ownership in the Pronghorn assets, which included a 50 percent undivided interest in a natural gas processing plant, both oil and gas gathering pipelines, an oil storage terminal and an oil pipeline in western North Dakota. The transaction closed in January 2017.

A majority of its pipeline and midstream business is transacted in the northern Great Plains and Rocky Mountain regions of the United States.

For information regarding natural gas gathering operations litigation, see Item 8 - Note 17 .

System Supply, System Demand and Competition Natural gas supplies emanate from traditional and nontraditional production activities in the region from both on-system and off-system supply sources. New incremental supply from nontraditional sources have developed, such as the Bakken area in Montana and North Dakota, which has helped offset declines in traditional regional supply sources and supports WBI Energy Transmission's transportation and storage services. In addition, off-system supply sources are available through the Company's interconnections with other pipeline systems. WBI Energy Transmission 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.

WBI Energy Transmission'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. These storage facilities enable customers to purchase natural gas throughout the year and meet winter peak requirements.

WBI Energy Transmission 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 its system near five natural gas producing basins and the availability of underground storage and gathering services, along with interconnections with other pipelines, serve to enhance its competitive position.

Although certain of WBI Energy Transmission'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.

WBI Energy Transmission transports substantially all of Montana-Dakota's natural gas, primarily utilizing firm transportation agreements, which for 2016 represented 39 percent of WBI Energy Transmission's subscribed firm transportation contract demand. The majority of the firm transportation agreements with Montana-Dakota expire in June 2022. In addition, Montana-Dakota has contracts with WBI Energy Transmission to provide firm storage services to facilitate meeting Montana-Dakota's winter peak requirements expiring in July 2035.

The nonregulated business competes with several midstream companies for existing customers, the expansion of its systems and the installation of new systems. Its 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.

Environmental Matters The pipeline and midstream operations are generally subject to federal, state and local environmental, facility-siting, zoning and planning laws and regulations. The Company believes it is in substantial compliance with those regulations.

Ongoing operations are subject to the Clean Air Act, the Clean Water Act, the RCRA and other state and federal regulations. Administration of many provisions of these laws has been delegated to the states where WBI Energy and its subsidiaries 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 as required by the National Environmental Policy Act are included in the FERC's environmental review process for both the construction and abandonment of WBI Energy Transmission's natural gas transmission pipelines, compressor stations and storage facilities.

The pipeline and midstream operations did not incur any material environmental expenditures in 2016 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2019 .

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 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, liquid asphalt for various commercial and roadway applications, various finished concrete products and other building materials and related contracting services.

The construction materials business had approximately $538 million in backlog at December 31, 2016 , compared to $491 million at December 31, 2015 . The Company anticipates that a significant amount of the current backlog will be completed during 2017 .

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 residential 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 Aggregate 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 high walls and other exposures of the aggregate reserves. Mine plans, production history and geologic data also are utilized to estimate reserve quantities. Most acquisitions are made of mature businesses with established reserves, as distinguished from exploratory-type properties.

Estimates are based on analyses of the data described above by experienced internal mining engineers, operating personnel and geologists. Property setbacks and other regulatory restrictions and limitations are identified to determine the total area available for mining. Data described previously are used to calculate the thickness of aggregate materials to be recovered. Topography associated with alluvial sand and gravel deposits is typically flat and volumes of these materials are calculated by applying the thickness of the resource over the areas available for mining. Volumes are then converted to tons by using an appropriate conversion factor. Typically, 1.5 tons per cubic yard in the ground is used for sand and gravel deposits.

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

Estimated reserves are probable reserves as defined in Securities Act Industry Guide 7. Remaining reserves are based on estimates of volumes that can be economically extracted and sold to meet current market and product applications. The reserve estimates include only salable tonnage and thus exclude waste materials that are generated in the crushing and processing phases of the operation. Approximately 911 million tons of the 989 million 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 2014 through 2016 . 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, 2016 , and sales for the years ended December 31, 2016 , 2015 and 2014 :

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)					
Production Area	owned	leased	owned	leased	**2016**	2015	2014	Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Anchorage, AK	—	—	1	—	**1,343**	1,837	1,665	15,972	N/A	10
Hawaii	—	6	—	—	**1,901**	1,892	1,840	52,091	2017-2064	28
Northern CA	—	—	9	1	**1,604**	1,580	1,340	46,411	2018	31
Southern CA	—	2	—	—	**224**	118	147	91,622	2035	Over 100
Portland, OR	1	3	5	3	**4,044**	3,562	3,244	217,712	2025-2055	60
Eugene, OR	3	4	7	—	**662**	819	928	155,090	2021-2046	Over 100
Central OR/WA/ID	—	1	6	2	**1,685**	1,493	1,254	88,467	2020-2077	60
Southwest OR	5	6	11	7	**2,689**	1,872	1,624	102,151	2017-2053	50
Central MT	—	—	3	2	**1,135**	1,383	1,260	29,310	2023-2027	23
Northwest MT	—	—	8	2	**1,514**	1,423	1,486	66,287	2017-2020	45
Wyoming	—	—	1	2	**742**	888	952	9,988	2019	12
Central MN	—	1	37	12	**2,831**	2,556	1,674	52,087	2017-2028	22
Northern MN	2	—	14	7	**537**	595	491	24,887	2017-2021	46
ND/SD	—	—	2	22	**1,643**	1,959	2,377	26,108	2017-2031	13
Texas	1	2	1	—	**1,243**	1,138	903	10,901	2022-2029	10
Sales from other sources					**3,783**	3,844	4,642			
					27,580	26,959	25,827	989,084		

The 989 million tons of estimated aggregate reserves at December 31, 2016 , are comprised of 467 million tons that are owned and 522 million tons that are leased. Approximately 31 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 21 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2014 through 2016 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 52 years. Some sites have leases that expire prior to the exhaustion of the estimated reserves. The estimated reserve life assumes, based on Knife River's experience, that leases will be renewed to allow sufficient time to fully recover these reserves.

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

	2016	2015	2014
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**1,022,513**	1,061,156	1,083,376
Acquisitions	**24,993**	7,406	12,343
Sales volumes*	**(23,797)**	(23,115)	(21,185)
Other**	**(34,625)**	(22,934)	(13,378)
End of year	**989,084**	1,022,513	1,061,156

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

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 the issues 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 the 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 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 Surface Mining Control and Reclamation Act, 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.

Knife River did not incur any material environmental expenditures in 2016 and, except as to what may be ultimately determined with regard to the issues described in the following paragraph, Knife River does not expect to incur any material expenditures related to environmental compliance with current laws and regulations through 2019 .

In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a commercial property site, acquired by Knife River - Northwest in 1999, and part of the Portland, Oregon, Harbor Superfund Site. For more information, see Item 8 - Note 17 .

Mine Safety The Dodd-Frank Act requires disclosure of certain mine safety information. For more information, see Item 4 - Mine Safety Disclosures.

Construction Services

General MDU Construction Services provides utility construction services specializing in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and other supplies. 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, 2016 , MDU Construction Services owned or leased facilities in 16 states. This space is used for offices, equipment yards, manufacturing, warehousing, storage and vehicle shops.

MDU Construction Services' backlog is comprised of the uncompleted portion of services to be performed under job-specific contracts. The backlog at December 31, 2016 , was approximately $475 million compared to $493 million at December 31, 2015 . MDU Construction Services expects to complete a significant amount of this backlog during 2017 . Due to the nature of its contractual arrangements, in many instances MDU Construction Services' customers are not committed to the specific volumes of services to be purchased under a contract, but rather MDU Construction Services is committed to perform these services if and to the extent requested by the customer. Therefore, there can be no assurance as to the customers' requirements during a particular period or that such estimates at any point in time are predictive of future revenues.

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

Competition MDU Construction Services operates in a highly competitive business environment. Most of MDU Construction Services' work is obtained on the basis of competitive bids or by negotiation of either cost-plus or fixed-price contracts. The workforce and equipment are highly mobile, providing greater flexibility in the size and location of MDU Construction Services' market area. Competition is based primarily on price and reputation for quality, safety and reliability. The size and location of the services provided, as well as the state of the economy, will be factors in the number of competitors that MDU Construction Services will encounter on any particular project. MDU Construction Services believes that the diversification of the services it provides, the markets it serves throughout the United States and the management of its workforce will enable it to effectively operate in this competitive environment.

Utilities and independent contractors represent the largest customer base for this segment. Accordingly, utility and subcontract work accounts for a significant portion of the work performed by MDU Construction Services and the amount of construction contracts is dependent to a certain extent on the level and timing of maintenance and construction programs undertaken by customers. MDU Construction Services relies on repeat customers and strives to maintain successful long-term relationships with these customers.

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

The nature of MDU Construction Services' operations is such that few, if any, environmental permits are required. Operational convenience supports the use of petroleum storage tanks in several locations, which are permitted under state programs authorized by the EPA. MDU Construction Services has no ongoing remediation related to releases from petroleum storage tanks. MDU Construction Services' operations are conditionally exempt small-quantity waste generators, subject to minimal regulation under the RCRA. Federal permits for specific construction and maintenance jobs that may require these permits are typically obtained by the hiring entity, and not by MDU Construction Services.

MDU Construction Services did not incur any material environmental expenditures in 2016 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2019 .

Discontinued Operations

General Discontinued operations includes the results of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense . In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. For more information on discontinued operations, see Item 8 - Note 2 and Supplementary Financial Information.

Item 1A. Risk Factors

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

Economic Risks

The Company's pipeline and midstream business is dependent on factors, including commodity prices and commodity price basis differentials, that are subject to various external influences that cannot be controlled.

These factors include: fluctuations in oil, NGL and natural gas production and prices; fluctuations in commodity price basis differentials; domestic and foreign supplies of oil, NGL and natural gas; political and economic conditions in oil producing countries; actions of the Organization of Petroleum Exporting Countries; and other risks incidental to the development and operations of natural gas pipeline systems. Continued prolonged depressed prices for oil, NGL and natural gas could impede the growth of the pipeline and midstream business, and could negatively affect the results of operations, cash flows and asset values of the Company's pipeline and midstream business.

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

The construction, startup and operation of pipelines and power generation and transmission facilities involve many risks, which may include: delays; breakdown or failure of equipment; inability to obtain required governmental permits and approvals; inability to obtain or renew easements; public opposition; inability to complete financing; inability to negotiate acceptable equipment acquisition, construction, fuel supply, off-take, transmission, transportation or other material agreements; changes in markets and market prices for power; cost increases and overruns; the risk of performance below expected levels of output or efficiency; and the inability to obtain full cost recovery in regulated rates. Such unanticipated events could negatively impact the Company's business, its results of operations and cash flows.

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

The global demand and price volatility for natural resources, interest rate changes, governmental budget constraints and the ongoing threat of terrorism can create volatility in the financial markets. Unfavorable economic conditions can negatively affect the level of public and private expenditures on projects and the timing of these projects which, in turn, can negatively affect the demand for the Company's products and services, primarily at the Company's construction businesses. The level of demand for construction products and services could be adversely impacted by the economic conditions in the industries the Company serves, as well as in the economy in general. State and federal budget issues may negatively affect the funding available for infrastructure spending. The ability of the Company's electric and natural gas distribution businesses to grow service territory and customer base is affected by the economic environments of the markets served. This economic volatility could have a material adverse effect on the Company's results of operations, cash flows and asset values.

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

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

- A significant economic downturn
- The financial distress of unrelated industry leaders in the same line of business
- Deterioration in capital market conditions
- Turmoil in the financial services industry
- Volatility in commodity prices
- Terrorist attacks

- Cyberattacks

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

The issuance of a substantial amount of the Company's common stock, whether issued in connection with an acquisition or otherwise, 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 the Company's customers or counterparties were to experience financial difficulties or file for bankruptcy, the Company could experience difficulty in collecting receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties could have a negative impact on the Company's results of operations and cash flows.

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

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

Environmental and Regulatory Risks

The Company's operations are subject to environmental laws and regulations that may increase costs of operations, impact or limit business plans, or expose the Company to environmental liabilities.

The Company is subject to environmental laws and regulations affecting many aspects of its operations, including laws and regulations regarding air and water quality, waste management and other environmental considerations. These laws and regulations can increase capital, operating and other costs, cause delays as a result of litigation and administrative proceedings, and create compliance, remediation, containment, monitoring and reporting obligations, particularly relating to electric generation and natural gas gathering, transmission and storage operations. These laws and regulations generally require the Company to obtain and comply with a variety of environmental licenses, permits, inspections and other approvals. Although the Company strives to comply with all applicable environmental laws and regulations, public and private entities and private individuals may interpret the Company's legal or regulatory requirements differently and seek injunctive relief or other remedies against the Company. The Company cannot predict the outcome, financial or operational, of any such litigation or administrative proceedings.

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, retire and replace certain facilities, install pollution controls, remediate environmental impacts, remove or reduce environmental hazards, or forego or limit the development of resources. Revised or new laws and regulations that increase compliance costs or restrict operations, particularly if costs are not fully recoverable from customers, could have a material adverse effect on the Company's results of operations and cash flows.

On April 17, 2015, the EPA published a rule, under the RCRA, for coal combustion residuals that regulates coal ash as a solid waste and not a hazardous waste. The rule requires ground water and location restriction evaluations to be conducted by October 2017 at ash impoundments and landfills not located at coal mines. In 2015, one ash impoundment at Lewis & Clark Station was replaced with a new concrete basin. Additional site and groundwater analyses may identify the need to upgrade or close additional impoundments or the Company may need to install replacement ash management systems. The cost of replacement ash impoundments or landfills may be material. If these costs are not fully recoverable from customers, they could have a material adverse effect on the Company's results of operations and cash flows.

On August 15, 2014, the EPA published a rule under Section 316(b) of the Clean Water Act, establishing requirements for water intake structures at existing steam electric generating facilities. The purpose of the rule is to reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures. The majority of the Company's electric generating facilities are either not subject to the rule or have completed studies that project compliance expenditures are not material. The Lewis & Clark Station will complete a study that will be submitted to the Montana DEQ by July 31, 2019, to be used in determining any required controls. It is unknown at this time what controls may be required at this facility or if compliance costs will be material. The installation schedule for any required controls would be established with the permitting agency after the study is completed.

Initiatives to reduce GHG emissions could adversely impact the Company's operations.

Concern that GHG emissions are contributing to global climate change has led to international, federal and state legislative and regulatory proposals to reduce or mitigate the effects of GHG emissions. The Company’s primary GHG emission is carbon dioxide from fossil fuels combustion at Montana-Dakota's electric generating facilities, particularly its coal-fired facilities. Approximately 50 percent of Montana-Dakota's owned generating capacity and approximately 75 percent of the electricity it generated in 2016 was from coal-fired facilities.

On October 23, 2015, the EPA published the Clean Power Plan rule that requires existing fossil fuel-fired electric generating facilities to reduce carbon dioxide emissions. On February 9, 2016, however, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending disposition of the applicants' petition for review in the D.C. Circuit Court and disposition of the applicants' petition for a writ of certiorari if such a writ is sought. As published, the rule required that by September 6, 2016, states submit to the EPA either a request for a two-year extension to submit a final state plan or a final plan demonstrating how emissions reductions will be achieved including emission limits in the form of an annual emission cap or an emission rate that will be applied to each fossil fuel-fired electric generating facility within the state starting in 2022. Emissions limits become more stringent from 2022 to 2030, with the 2030 emission limits applying thereafter. It is unknown at this time what each state will require for emissions limits or reductions from each of Montana-Dakota's owned and jointly owned fossil fuel-fired electric generating units. Compliance costs will become clearer as final state plans are submitted to the EPA. The effective date and compliance dates in the rule are expected to be addressed in a future decision made by the United States Supreme Court.

On January 14, 2015, the federal government of the United States announced a goal to reduce methane emissions from the oil and natural gas industry by 40 percent to 45 percent below 2012 levels by 2025. On June 3, 2016, the EPA published a rule updating new source performance standards for the oil and natural gas industry. The rule builds on 2012 requirements to reduce volatile organic compound emissions from oil and natural gas sources by establishing requirements to reduce methane emissions from previously regulated sources, as well as adding volatile organic compound and methane requirements for sources previously not covered by the rule. The rule impacts new and modified natural gas gathering and boosting stations and transmission and storage compressor stations. WBI Energy is developing implementation plans for complying with the rule. In addition, on March 10, 2016, the EPA announced plans to reduce emissions from the oil and natural gas industry by moving to regulate emissions from existing sources. On November 10, 2016, the EPA issued an Information Collection Request to gather information on existing sources of methane emissions, technologies to reduce emissions and the costs of those technologies in the oil and natural gas industry. Several companies, including WBI Energy, were selected to respond to the Information Collection Request. The information collected will be used to develop comprehensive regulations to reduce methane emissions from existing sources. It is unknown at this time how the Company will be impacted or if compliance costs will be material.

On September 15, 2016, the Washington DOE issued a Clean Air rule that requires carbon dioxide emission reductions from various industries in the state, including emissions from the combustion of natural gas supplied to end-use customers by natural gas distribution companies, such as Cascade. In 2017, the rule requires Cascade to hold carbon dioxide emissions to a baseline, equal to the average emissions in 2012 to 2016. Beginning in 2018, annual carbon dioxide emissions are reduced by an additional 1.7 percent of the baseline from the previous year's emissions. Compliance for natural gas suppliers is to be achieved through purchasing emissions credits from projects located within the state of Washington and, to a limited and declining extent, out-of-state allowances. Purchasing emissions credits and allowances will increase operating costs for Cascade. If Cascade is not able to receive timely and full recovery of compliance costs from its customers, such costs could adversely impact the results of its operations. On September 27, 2016 and September 30, 2016, Cascade and three other natural gas distribution utility companies jointly filed complaints in the United States District Court for the Eastern District of Washington and the Thurston County Superior Court, respectively, asking the courts to deem the rule invalid. The companies assert that the Washington DOE undertook this rulemaking without the requisite statutory authority. The Thurston County Superior Court is scheduled to hear oral arguments on April 14, 2017, while litigation in the United States District Court for the Eastern District of Washington has been held in abeyance until there is a ruling in the Thurston County Superior Court.

Additional treaties, legislation or regulations to reduce GHG emissions may be adopted that affect the Company's utility operations by requiring additional energy conservation efforts or renewable energy sources, as well as other mandates that could significantly increase capital expenditures and operating costs or reduce demand for the Company's utility services. If the Company’s utility operations do not receive timely and full recovery of GHG emission compliance costs from customers, then such costs could adversely impact the results of its operations and cash flows.

The Company monitors, analyzes and reports GHG emissions from its other operations as required by applicable laws and regulations. The Company will continue to monitor GHG regulations and their potential impact on operations.

Due to the uncertain availability of technologies to control GHG emissions and the unknown obligations that potential GHG emission legislation or regulations may create, the Company cannot determine the potential financial impact on its operations.

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

The Company is subject to regulation or governmental actions by federal, state and local regulatory agencies with respect to, among other things, allowed rates of return and recovery of investment and cost, financing, rate structures, health care coverage and cost, taxes, franchises 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 as well as for acquisitions by the Company. The approval process could be lengthy and the outcome uncertain.

The Company's electric and natural gas transmission and distribution operations involve risks that may result in accidents. These events and pipeline safety regulation costs could adversely affect the Company's business and its results of operations and cash flows.

The Company's electric and natural gas transmission and distribution activities include a variety of operating risks, such as leaks, explosions and mechanical problems, which could result in loss of human life, personal injury, property damage, environmental pollution, impairment of operations and substantial losses. The Company maintains insurance against some, but not all, of these risks and losses. The occurrence of these losses not fully covered by insurance could have a material effect on the Company's financial position, results of operations and cash flows.

Additionally, the operating or other costs that may be required to comply with current pipeline safety regulations and potential new regulations under various agencies could be significant. The regulations require verification of pipeline infrastructure records by pipeline owners and operators to confirm the maximum allowable operating pressure of certain lines. Increased emphasis on pipeline safety issues and increased regulatory scrutiny may result in penalties and higher costs of operations. If these costs are not fully recoverable from customers, they could have a material adverse effect on the Company's results of operations and cash flows.

Other Risks

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

The Company's results of operations can be affected by changes in the weather. Weather conditions influence the demand for electricity and natural gas, affect the price of energy commodities, affect the ability to perform services at the construction materials and contracting and construction services businesses and affect ongoing operation and maintenance and construction activities for the pipeline and midstream business. In addition, severe weather can be destructive, causing outages, and/or property damage, which could require additional costs to be incurred. As a result, adverse weather conditions could negatively affect the Company's results of operations, financial position and cash flows.

Competition exists in all of the Company's businesses.

All of the Company's businesses are subject to competition. Construction services' competition is based primarily on price and reputation for quality, safety and reliability. 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 and other factors. The pipeline and midstream business competes with several pipelines for access to natural gas supplies and gathering, transportation and storage business. Competition could negatively affect the Company's results of operations, financial position and cash flows.

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

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

Costs related to obligations under MEPPs could have a material negative effect on the Company's results of operations and cash flows.

Various operating subsidiaries of the Company participate in approximately 75 MEPPs for employees represented by certain unions. The Company is required to make contributions to these plans in amounts established under numerous collective bargaining agreements between the operating subsidiaries and those unions.

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

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

In addition, pursuant to ERISA, as amended by MPPAA, the Company could incur a partial or complete withdrawal liability upon withdrawing from a plan, exiting a market in which it does business with a union workforce or upon termination of a plan to the extent these plans are underfunded. The Company could also incur additional withdrawal liability if its withdrawal from a plan is determined by that plan to be part of a mass withdrawal.

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

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

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

The Company may be subject to potential material liabilities relating to the past sale of assets or businesses, primarily arising from events prior to sale.

The Company previously sold its oil and natural gas assets and its membership interests in Dakota Prairie Refining. The Company may be subject to potential liabilities, either directly or through indemnification of the buyers or others, relating to these transactions or other sales, primarily arising from events prior to the sale, or from breaches of any representations, warranties or covenants in the purchase and sale agreements.

Other factors that could impact the Company's businesses.

The following are other factors that should be considered for a better understanding of the financial condition of the Company. These other factors may impact the Company's financial results in future periods.

- Acquisition, disposal and impairments of assets or facilities
- Changes in operation, performance and construction of plant facilities or other assets
- Changes in present or prospective generation
- The ability to obtain adequate and timely cost recovery for the Company's regulated operations through regulatory proceedings
- The availability of economic expansion or development opportunities
- Population growth rates and demographic patterns
- Market demand for, available supplies of, and/or costs of, energy- and construction-related products and services
- The cyclical nature of large construction projects at certain operations
- Changes in tax rates, policies or tax reform
- 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 contract counterparties to meet their contractual obligations
- Changes in accounting principles and/or the application of such principles to the Company
- Changes in technology
- Changes in legal or regulatory proceedings
- The ability to effectively integrate the operations and the internal controls of acquired companies
- The ability to attract and retain skilled labor and key personnel
- Increases in employee and retiree benefit costs and funding requirements

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings, see Item 8 - Note 17 , which is incorporated herein by reference.

Item 4. Mine Safety Disclosures

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

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 2016 and 2015 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2016			
First quarter	**$19.55**	**$15.57**	**$.1875**
Second quarter	**24.01**	**18.70**	**.1875**
Third quarter	**25.79**	**22.47**	**.1875**
Fourth quarter	**29.92**	**24.49**	**.1925**
			$.7550
2015			
First quarter	$24.51	$20.01	$.1825
Second quarter	23.12	19.22	.1825
Third quarter	19.73	16.15	.1825
Fourth quarter	19.66	16.26	.1875
			$.7350

As of December 31, 2016 , the Company's common stock was held by approximately 12,400 stockholders of record.

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. The declaration and payment of dividends is at the sole discretion of the board of directors, subject to limitations imposed by the Company's credit agreements, federal and state laws, and applicable regulatory limitations. For more information on factors that may limit the Company's ability to pay dividends, see Item 8 - Note 9 .

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

ISSUER PURCHASES OF EQUITY SECURITIES

Period	(a) Total Number of Shares (or Units) Purchased (1)	(b) Average Price Paid per Share (or Unit)	(c) Total Number of Shares (or Units) Purchased as Part of Publicly Announced Plans or Programs (2)	(d) Maximum Number (or Approximate Dollar Value) of Shares (or Units) that May Yet Be Purchased Under the Plans or Programs (2)
October 1 through October 31, 2016	—			
November 1 through November 30, 2016	34,974	$28.30		
December 1 through December 31, 2016	2,244	28.96		
Total	37,218			

(1) Represents shares of common stock purchased on the open market in connection with annual stock grants made to the Company's non-employee directors and for those directors who elected to receive additional shares of common stock in lieu of a portion of their cash retainer.
(2) Not applicable. The Company does not currently have in place any publicly announced plans or programs to purchase equity securities.

Item 6. Selected Financial Data

	2016	2015	2014	2013	2012	2011
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 322,356**	$ 280,615	$ 277,874	$ 257,260	$ 236,895	$ 225,468
Natural gas distribution	**766,115**	817,419	921,986	851,945	754,848	907,400
Pipeline and midstream	**141,602**	154,904	157,292	144,568	142,610	152,972
Construction materials and contracting	**1,874,270**	1,904,282	1,765,330	1,712,137	1,617,425	1,510,010
Construction services	**1,073,272**	926,427	1,119,529	1,039,839	938,558	854,389
Other	**8,643**	9,191	9,364	9,620	10,370	11,446
Intersegment eliminations	**(57,430)**	(78,786)	(136,302)	(95,201)	(74,595)	(68,482)
	$ 4,128,828	$ 4,014,052	$ 4,115,073	$ 3,920,168	$ 3,626,111	$ 3,593,203
Operating income (loss) (000's):						
Electric	**$ 68,497**	$ 57,955	$ 61,331	$ 54,274	$ 49,852	$ 49,096
Natural gas distribution	**65,014**	53,810	65,633	78,829	67,579	82,856
Pipeline and midstream	**43,374**	29,988	46,713	20,896	49,139	45,365
Construction materials and contracting	**178,719**	146,026	86,462	93,629	57,864	51,092
Construction services	**53,705**	43,376	82,309	85,246	66,531	39,144
Other	**(189)**	(8,438)	(5,366)	(4,384)	(5,325)	(7,079)
Intersegment eliminations	**—**	(2,942)	(9,900)	(7,176)	—	—
	$ 409,120	$ 319,775	$ 327,182	$ 321,314	$ 285,640	$ 260,474
Earnings (loss) on common stock (000's):						
Electric	**$ 42,222**	$ 35,914	$ 36,731	$ 34,837	$ 30,634	$ 29,258
Natural gas distribution	**27,102**	23,607	30,484	37,656	29,409	38,398
Pipeline and midstream	**23,435**	13,250	24,666	7,701	26,588	23,082
Construction materials and contracting	**102,687**	89,096	51,510	50,946	32,420	26,430
Construction services	**33,945**	23,762	54,432	52,213	38,429	21,627
Other	**(3,231)**	(14,941)	(7,386)	(10,776)	(7,209)	(5,918)
Intersegment eliminations	**6,251**	5,016	(6,095)	(4,307)	—	—
Earnings on common stock before income (loss) from discontinued operations	**232,411**	175,704	184,342	168,270	150,271	132,877
Income (loss) from discontinued operations, net of tax*	**(300,354)**	(834,080)	109,311	109,615	(151,710)	79,464
Loss from discontinued operations attributable to noncontrolling interest	**(131,691)**	(35,256)	(3,895)	(363)	—	—
	$ 63,748	$ (623,120)	$ 297,548	$ 278,248	$ (1,439)	$ 212,341
Earnings (loss) per common share before discontinued operations - diluted	**$ 1.19**	$ .90	$ .96	$ .89	$ .80	$ .70
Discontinued operations attributable to the Company, net of tax	**(.86)**	(4.10)	.59	.58	(.81)	.42
	$ .33	$ (3.20)	$ 1.55	$ 1.47	$ (.01)	$ 1.12
Common Stock Statistics						
Weighted average common shares outstanding -diluted (000's)	**195,618**	194,986	192,587	189,693	188,826	188,905
Dividends declared per common share	**$ .7550**	$ .7350	$ .7150	$ .6950	$ .6750	$ .6550
Book value per common share	**$ 11.78**	$ 12.83	$ 16.66	$ 15.01	$ 13.95	$ 14.62
Market price per common share (year end)	**$ 28.77**	$ 18.32	$ 23.50	$ 30.55	$ 21.24	$ 21.46
Market price ratios:						
Dividend payout**	**63%**	82%	74%	78%	84%	94%
Yield	**2.7%**	4.1%	3.1%	2.3%	3.2%	3.1%
Market value as a percent of book value	**244.2%**	142.8%	141.1%	203.5%	152.3%	146.8%

* Reflects oil and natural gas properties noncash write-downs of $315.3 million (after tax) and $246.8 million (after tax) in 2015 and 2012, respectively, and fair value impairments of assets held for sale of $157.8 million (after tax) and $475.4 million (after tax) in 2016 and 2015, respectively.

** Based on continuing operations.

Item 6. Selected Financial Data (continued)

	2016	2015	2014	2013	2012	2011
General						
Total assets (000's)	**$ 6,284,467**	$ 6,565,154	$ 7,805,405	$ 7,043,365	$ 6,675,609	$ 6,539,676
Total long-term debt (000's)	**$ 1,790,159**	$ 1,796,163	$ 2,016,198	$ 1,773,050	$ 1,738,833	$ 1,418,693
Capitalization ratios:						
Total equity	**56%**	58%	62%	62%	60%	66%
Total debt	**44**	42	38	38	40	34
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**3,258,537**	3,316,017	3,308,358	3,173,086	2,996,528	2,878,852
Electric system summer and firm purchase contract ZRCs (Interconnected system)	**559.7**	547.3	584.0	583.5	552.8	572.8
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected system)	**559.7**	547.3	522.4	508.3	550.7	524.2
All-time demand peak - kW (Interconnected system)	**611,542**	611,542	582,083	573,587	573,587	535,761
Electricity produced (thousand kWh)	**2,626,763**	1,898,160	2,519,938	2,430,001	2,299,686	2,488,337
Electricity purchased (thousand kWh)	**904,702**	1,658,002	1,010,422	971,261	870,516	645,567
Average cost of fuel and purchased power per kWh	**$ .021**	$ .024	$ .025	$ .025	$ .023	$ .021
Natural Gas Distribution						
Sales (Mdk)	**99,296**	95,559	104,297	108,260	93,810	103,237
Transportation (Mdk)	**147,592**	154,225	145,941	149,490	132,010	124,227
Degree days (% of normal)						
Montana-Dakota/Great Plains	**89%**	88%	103%	105%	84%	101%
Cascade	**87%**	83%	89%	98%	96%	103%
Intermountain	**96%**	89%	95%	110%	91%	107%
Pipeline and Midstream						
Transportation (Mdk)	**285,254**	290,494	233,483	178,598	137,720	113,217
Gathering (Mdk)	**20,049**	33,441	38,372	40,737	47,084	66,500
Customer natural gas storage balance (Mdk)	**26,403**	16,600	14,885	26,693	43,731	36,021
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**27,580**	26,959	25,827	24,713	23,285	24,736
Asphalt (tons)	**7,203**	6,705	6,070	6,228	5,988	6,709
Ready-mixed concrete (cubic yards)	**3,655**	3,592	3,460	3,223	3,157	2,864
Aggregate reserves (000's tons)	**989,084**	1,022,513	1,061,156	1,083,376	1,088,236	1,088,833

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 the regulated energy delivery and construction materials and services businesses 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
- Divestiture of certain assets to fund capital growth projects throughout the Company

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities, the issuance from time to time of debt and equity securities and asset sales. For more information on the Company's 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 businesses, see Item 8 - Note 13 .

Key Strategies and Challenges

Electric and Natural Gas Distribution

Strategy Provide safe and reliable competitively priced energy and related services to customers. The electric and natural gas distribution segments continually seek opportunities to retain, grow and expand their customer base through extensions of existing operations, including building and upgrading electric generation and transmission and natural gas systems, 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 timely recovery and permitted returns on investment as well as subject to certain operational, system integrity and environmental regulations. These regulations can require substantial investment to upgrade facilities. The ability of these segments to grow through acquisitions is subject to significant competition. In addition, the ability of both segments to grow service territory and customer base is affected by the economic environment of the markets served and competition from other energy providers and fuels. The construction of any new electric generating facilities, transmission lines and other service facilities is subject to increasing cost and lead time, extensive permitting procedures, and federal and state legislative and regulatory initiatives, which will necessitate increases in electric energy prices. Legislative and regulatory initiatives to increase renewable energy resources and reduce GHG emissions could impact the price and demand for electricity and natural gas and could result in the retirement of certain electric generating facilities before they are fully depreciated.

Pipeline and Midstream

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 investments in and acquisitions of energy-related assets and companies both in its current operating areas and beyond its Rocky Mountain and northern Great Plains base. Incremental and new growth opportunities include: access to new energy sources for storage, gathering and transportation services; expansion of existing storage, gathering and transmission facilities; incremental pipeline projects which expand pipeline capacity; and expansion of the pipeline and midstream business to include liquid pipelines and processing activities.

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

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; develop and recruit talented employees; and continue growth through organic and acquisition opportunities. Vertical integration allows the segment to manage operations from aggregate mining to final lay-down of concrete and asphalt, with control of and access to permitted aggregate reserves being significant. A key element of the Company's long-term strategy for this business is to further expand its market presence in the higher-margin materials business (rock, sand, gravel, liquid asphalt, asphalt concrete, ready-mixed concrete and related products), complementing and expanding on the Company's expertise.

Challenges Recruitment and retention of key personnel and volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel, are ongoing challenges. This business unit expects to continue cost containment efforts, positioning its operations for the resurgence in the private market, while continuing the emphasis on industrial, energy and public works projects.

Construction Services
Strategy Provide a superior return on investment by: building new and strengthening existing customer relationships; effectively controlling costs; retaining, developing and recruiting talented employees; growing through organic and acquisition opportunities; and focusing efforts on projects that will permit higher margins while properly managing risk.

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

For more 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 more information on 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,	**2016**	2015	2014
	(Dollars in millions, where applicable)		
Electric	**$ 42.2**	$ 35.9	$ 36.7
Natural gas distribution	**27.1**	23.6	30.5
Pipeline and midstream	**23.4**	13.3	24.7
Construction materials and contracting	**102.7**	89.1	51.5
Construction services	**33.9**	23.8	54.5
Other	**(3.2)**	(15.0)	(7.4)
Intersegment eliminations	**6.3**	5.0	(6.2)
Earnings before discontinued operations	**232.4**	175.7	184.3
Income (loss) from discontinued operations, net of tax	**(300.4)**	(834.1)	109.3
Loss from discontinued operations attributable to noncontrolling interest	**(131.7)**	(35.3)	(3.9)
Earnings (loss) on common stock	**$ 63.7**	$ (623.1)	$ 297.5
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	**$ 1.19**	$ .90	$ .96
Discontinued operations, net of tax	**(.86)**	(4.10)	.59
Earnings (loss) per common share - basic	**$ .33**	$ (3.20)	$ 1.55
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	**$ 1.19**	$ .90	$ .96
Discontinued operations, net of tax	**(.86)**	(4.10)	.59
Earnings (loss) per common share - diluted	**$ .33**	$ (3.20)	$ 1.55

2016 compared to 2015 The Company recognized consolidated earnings of $63.7 million in 2016, compared to a consolidated loss of $623.1 million in 2015. This increase was due to:

- Discontinued operations which reflect the absence in 2016 of fair value impairments of the exploration and production business's assets of $475.4 million (after tax) and a noncash write-down of oil and natural gas properties of $315.3 million (after tax) offset in part by a fair value impairment of the refining business of $156.7 million (after tax) in 2016
- Higher construction margins and revenues and higher asphalt and aggregate volumes and margins at the construction materials and contracting business
- Other loss decreased primarily the result of lower operation and maintenance and interest expense due to the sales of the exploration and production and refining businesses
- Higher inside electrical workloads and margins in the Western region offset in part by lower equipment sales and rental margins at the construction services business

- Absence in 2016 of impairments of natural gas gathering assets of $10.6 million (after tax) partially offset by a fair value impairment in 2016 of $1.4 million (after tax) associated with the sale of Pronghorn at the pipeline and midstream business
- Increased electric retail sales margins, largely due to approved rate recovery, partially offset by higher operation and maintenance expense and higher depreciation, depletion and amortization expense at the electric business

2015 compared to 2014 The Company recognized a consolidated loss of $623.1 million in 2015, compared to consolidated earnings of $297.5 million in 2014. This decrease was due to:

- Discontinued operations which had fair value impairments of the exploration and production business's assets of $475.4 million (after tax), a $315.3 million after-tax noncash write-down of oil and natural gas properties, decreased average realized commodity prices and decreased production
- Lower workloads and margins in the Western region and lower equipment rental sales and margins at the construction services business
- Impairments of natural gas gathering assets of $10.6 million (after tax) at the pipeline and midstream business
- Higher depreciation, depletion and amortization expense due to plant additions and lower natural gas sales volumes offset in part by natural gas retail rate increases at the natural gas distribution business

Partially offsetting these increases were higher earnings on all product lines at the construction materials and contracting business.

Financial and Operating Data

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

Electric

Years ended December 31,	2016	2015	2014
	(Dollars in millions, where applicable)		
Operating revenues	**$ 322.3**	$ 280.6	$ 277.9
Operating expenses:			
Fuel and purchased power	**75.5**	86.2	89.3
Operation and maintenance	**115.2**	87.7	81.1
Depreciation, depletion and amortization	**50.2**	37.6	35.0
Taxes, other than income	**12.9**	11.1	11.1
	253.8	222.6	216.5
Operating income	**68.5**	58.0	61.4
Earnings	**$ 42.2**	$ 35.9	$ 36.7
Retail sales (million kWh):			
Residential	**1,132.5**	1,173.9	1,225.3
Commercial	**1,491.8**	1,499.6	1,471.3
Industrial	**544.2**	550.3	520.4
Other	**90.0**	92.2	91.4
	3,258.5	3,316.0	3,308.4
Average cost of fuel and purchased power per kWh	**$ .021**	$ .024	$ .025

2016 compared to 2015 Electric earnings increased $6.3 million (18 percent) compared to the prior year due to:

- Increased electric retail sales margins, largely due to approved final and interim rate increases reduced in part by decreased electric sales volumes of 2 percent, largely decreased residential customer volumes
- Favorable income tax changes, which includes $10.1 million due to higher production tax credits

Partially offsetting these increase s were:

- Higher operation and maintenance expense of $17.1 million (after tax) primarily due to higher contract services and higher payroll-related costs
- Higher depreciation, depletion and amortization expense of $7.8 million (after tax) due to increased property, plant and equipment balances
- Lower other income, which includes $7.1 million (after tax) primarily related to AFUDC
- Higher interest expense, which includes $4.4 million (after tax) largely the result of higher long-term debt

Certain of the higher operation and maintenance expense, higher depreciation, depletion and amortization expense and higher production tax credits in 2016, due to increased capital investments, are potentially recoverable and/or refundable through the rate recovery process. The previous table also reflects lower average cost of fuel and purchased power per kWh due to no fuel and purchased power costs associated with the Thunder Spirit Wind farm.

2015 compared to 2014 Electric earnings decreased $800,000 (2 percent) compared to the prior year due to:

- Higher operation and maintenance expense, which includes $4.3 million (after tax) largely related to higher contract services, primarily related to a planned outage at an electric generation station, and higher payroll and benefit-related costs
- Higher depreciation, depletion and amortization expense of $1.6 million (after tax) due to increased property, plant and equipment balances
- Higher net interest expense, which includes $1.1 million (after tax) due to higher long-term debt

Partially offsetting these decreases were:

- Increased electric retail sales margins, primarily due to rate recovery of new generation
- Higher other income, which includes $3.5 million (after tax) primarily related to AFUDC

Natural Gas Distribution

Years ended December 31,	2016	2015	2014
	(Dollars in millions, where applicable)		
Operating revenues	$ 766.1	$ 817.4	$ 922.0
Operating expenses:			
Purchased natural gas sold	431.5	499.0	603.2
Operation and maintenance	158.1	153.5	150.2
Depreciation, depletion and amortization	65.4	64.8	54.7
Taxes, other than income	46.1	46.3	48.3
	701.1	763.6	856.4
Operating income	65.0	53.8	65.6
Earnings	$ 27.1	$ 23.6	$ 30.5
Volumes (MMdk)			
Sales:			
Residential	56.2	54.0	58.8
Commercial	38.9	37.6	41.0
Industrial	4.2	4.0	4.5
	99.3	95.6	104.3
Transportation:			
Commercial	1.8	1.8	1.9
Industrial	145.8	152.4	144.0
	147.6	154.2	145.9
Total throughput	246.9	249.8	250.2
Degree days (% of normal)*			
Montana-Dakota/Great Plains	89%	88%	103%
Cascade	87%	83%	89%
Intermountain	96%	89%	95%
Average cost of natural gas, including transportation, per dk	$ 4.35	$ 5.22	$ 5.78

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

2016 compared to 2015 The natural gas distribution business experienced an increase in earnings of $3.5 million (15 percent) compared to the prior year due to higher natural gas retail sales margins resulting from increased retail sales volumes of 4 percent to all customer classes due to customer growth and colder weather in certain regions, as well as final and interim rate increases, partially offset by higher operation and maintenance expense, which includes $4.6 million (after tax) largely higher payroll-related costs, and higher depreciation, depletion and amortization expense from increased property, plant and equipment balances.

The previous table also includes lower nonutility project costs reflected in operation and maintenance expense, as well as the pass-through of lower natural gas prices which are reflected in the decrease in both sales revenue and purchased natural gas sold in 2016.

2015 compared to 2014 The natural gas distribution business experienced a decrease in earnings of $6.9 million (23 percent) compared to the prior year due to:

- Higher depreciation, depletion and amortization expense of $6.3 million (after tax), largely resulting from increased property, plant and equipment balances
- Lower natural gas sales margins, primarily lower retail sales volumes of 8 percent to all customer classes due to warmer weather than the prior year, partially offset by approved rate increases effective in 2015 and increased transportation volumes

The pass-through of lower natural gas prices is reflected in the decrease in both sales revenue and purchased natural gas sold in 2015.

Pipeline and Midstream

Years ended December 31,	**2016**	2015	2014
		(Dollars in millions)	
Operating revenues	**$ 141.6**	$ 154.9	$ 157.3
Operating expenses:			
Operation and maintenance	**61.4**	84.7	68.0
Depreciation, depletion and amortization	**24.9**	28.0	29.8
Taxes, other than income	**11.9**	12.2	12.8
	98.2	124.9	110.6
Operating income	**43.4**	30.0	46.7
Earnings	**$ 23.4**	$ 13.3	$ 24.7
Transportation volumes (MMdk)	**285.3**	290.5	233.5
Natural gas gathering volumes (MMdk)	**20.0**	33.4	38.4
Customer natural gas storage balance (MMdk):			
Beginning of period	**16.6**	14.9	26.7
Net injection (withdrawal)	**9.8**	1.7	(11.8)
End of period	**26.4**	16.6	14.9

2016 compared to 2015 Pipeline and midstream earnings increased $10.1 million (77 percent) largely due to:

- Lower operation and maintenance expense, which includes $13.6 million (after tax) largely due to the absence in 2016 of impairments of natural gas gathering assets of $10.6 million (after tax), as discussed in Item 8 - Notes 1 and 5 , lower payroll-related costs and lower material costs partially offset by a fair value impairment in 2016 of $1.4 million (after tax) associated with the sale of Pronghorn, as discussed in Item 8 - Note 2
- Lower depreciation, depletion and amortization of $1.9 million (after tax), largely due to the sale of certain non-strategic natural gas gathering assets in the fourth quarter of 2015
- Higher storage services earnings, primarily due to higher average interruptible storage balances
- Lower interest expense of $1.2 million (after tax), primarily the result of lower debt interest rates and balances

Partially offsetting the earnings increase was lower gathering and processing earnings of $8.0 million (after tax) resulting from lower natural gas gathering volumes, primarily due to the sale of certain non-strategic assets, as previously discussed, and lower oil gathering volumes, partially offset by higher oil gathering rates at Pronghorn.

2015 compared to 2014 Pipeline and midstream earnings decreased $11.4 million (46 percent) largely due to:

- Impairments of natural gas gathering assets of $10.6 million (after tax) included in operation and maintenance expense, as discussed in Item 8 - Notes 1 and 5
- Lower gathering and processing earnings of $5.2 million (after tax), primarily lower processing prices and natural gas gathering volumes

- Lower storage services earnings, primarily due to lower interruptible storage withdrawal volumes and lower average balances

Partially offsetting the earnings decrease was higher earnings of $5.7 million (after tax) due to higher transportation revenue, primarily resulting from higher rates due to a rate case settlement effective in May 2014, and increased volumes.

Construction Materials and Contracting

Years ended December 31,		2016		2015		2014
				(Dollars in millions)		
Operating revenues	$	**1,874.3**	$	1,904.3	$	1,765.3
Operating expenses:						
Operation and maintenance		**1,595.4**		1,652.3		1,571.5
Depreciation, depletion and amortization		**58.4**		65.9		68.6
Taxes, other than income		**41.8**		40.1		38.8
		1,695.6		1,758.3		1,678.9
Operating income		**178.7**		146.0		86.4
Earnings	$	**102.7**	$	89.1	$	51.5
Sales (000's):						
Aggregates (tons)		**27,580**		26,959		25,827
Asphalt (tons)		**7,203**		6,705		6,070
Ready-mixed concrete (cubic yards)		**3,655**		3,592		3,460

2016 compared to 2015 Earnings at the construction materials and contracting business increased $13.6 million (15 percent) due to:

- Higher earnings of $8.1 million (after tax) resulting from higher construction margins and revenues due to more available work in most regions
- A $6.7 million (after tax) reduction in 2016 to a previously recorded MEPP withdrawal liability compared to an increase to a MEPP withdrawal liability of $1.5 million (after tax) in 2015, as discussed in Item 8 - Note 14
- Higher earnings of $2.9 million (after tax) resulting from higher asphalt volumes and margins, which includes lower asphalt oil and production costs
- Higher earnings of $2.3 million (after tax) resulting from higher aggregate volumes and margins due to increased demand

Partially offsetting these increases were:

- Higher effective income tax rates
- Lower earnings of $1.3 million (after tax) from other product lines

Lower diesel fuel costs contributed to higher earnings from all product lines.

2015 compared to 2014 Earnings at the construction materials and contracting business increased $37.6 million (73 percent) due to:

- Higher earnings of $9.1 million (after tax) resulting from higher ready-mixed concrete margins and volumes
- Higher earnings of $7.2 million (after tax) resulting from higher asphalt margins and volumes, which includes lower asphalt oil costs
- An increase to a MEPP withdrawal liability of $1.5 million (after tax) in 2015, compared to $8.4 million (after tax) in 2014, as discussed in Item 8 - Note 14
- Higher earnings of $6.1 million (after tax) resulting from higher construction revenues and margins including the effects of favorable weather
- Higher earnings of $1.6 million (after tax) resulting from higher aggregate margins and volumes
- Higher earnings resulting from higher other product line margins and volumes

Partially offsetting these increases were higher selling, general and administrative expense of $5.7 million (after tax), largely related to higher payroll-related and other costs.

Lower diesel fuel costs contributed to higher earnings from all product lines.

Construction Services

Years ended December 31,	2016	2015	2014
		(In millions)	
Operating revenues	$ 1,073.3	$ 926.4	$ 1,119.5
Operating expenses:			
Operation and maintenance	965.3	838.5	990.7
Depreciation, depletion and amortization	15.3	13.4	12.9
Taxes, other than income	39.0	31.1	33.6
	1,019.6	883.0	1,037.2
Operating income	53.7	43.4	82.3
Earnings	$ 33.9	$ 23.8	$ 54.5

2016 compared to 2015 Construction services earnings increased $10.1 million (43 percent) largely due to:

- Higher earnings of $15.8 million (after tax) in the Western region largely due to higher workloads and margins resulting from the successful completion of construction projects in certain markets, as well as lower labor costs due to increased efficiencies and lower workers' compensation claim costs
- Higher earnings of $3.5 million (after tax) resulting from the sale of a non-strategic asset in 2015

These increases were partially offset by:

- Higher selling, general and administrative expense of $4.0 million (after tax), primarily due to higher payroll and benefit-related costs and higher bad debt expense
- Lower equipment sales and rental margins due to decreased customer demand
- Lower earnings of $1.6 million (after tax) in the Central region due to lower margins, largely the result of the loss on a project

2015 compared to 2014 Construction services earnings decreased $30.7 million (56 percent) due to:

- Lower earnings of $25.1 million (after tax) largely due to lower workloads and margins in the Western region resulting from substantial completion of significant projects in 2014, lower equipment sales and rental margins, lower margins in the Central region and lower electrical supply sales and margins
- The absence of the favorable resolution of certain income tax matters and higher income tax benefits in 2014

These decreases were partially offset by lower selling, general and administrative expense of $3.0 million (after tax), largely related to lower payroll and benefit-related costs.

Other

Years ended December 31,	2016	2015	2014
		(In millions)	
Operating revenues	$ 8.6	$ 9.2	$ 9.4
Operating expenses:			
Operation and maintenance	6.6	15.4	12.3
Depreciation, depletion and amortization	2.1	2.1	2.2
Taxes, other than income	.1	.1	.2
	8.8	17.6	14.7
Operating loss	(.2)	(8.4)	(5.3)
Loss	$ (3.2)	$ (15.0)	$ (7.4)

Included in Other are general and administrative costs and interest expense previously allocated to the exploration and production and refining businesses that do not meet the criteria for income (loss) from discontinued operations.

2016 compared to 2015 Other loss decreased $11.8 million compared to the prior year primarily due to lower operation and maintenance expense and interest expense previously allocated to the exploration and production business, due to the sale of that business which included the repayment of long-term debt. Also contributing to the decreased loss was lower operation and maintenance expense in 2016 due to the absence of a 2015 corporate asset impairment and the absence of a 2015 foreign currency translation loss including the effects of the sale of the Company's remaining interest in the Brazilian Transmission Lines.

2015 compared to 2014 Other loss increased $7.6 million compared to the prior year primarily due to the absence of prior year income tax benefits; higher operation and maintenance expense, largely a corporate asset impairment; as well as a foreign currency translation loss including the effects of the sale of the Company's remaining interest in the Brazilian Transmission Lines.

Discontinued Operations

Years ended December 31,		2016		2015		2014
				(In millions)		
Income (loss) from discontinued operations before intercompany eliminations, net of tax	$	**(303.2)**	$	(829.9)	$	108.8
Intercompany eliminations*		**2.8**		(4.2)		.5
Income (loss) from discontinued operations, net of tax		**(300.4)**		(834.1)		109.3
Loss from discontinued operations attributable to noncontrolling interest		**(131.7)**		(35.3)		(3.9)
Income (loss) from discontinued operations attributable to the Company, net of tax	$	**(168.7)**	$	(798.8)	$	113.2

* Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations .

2016 compared to 2015 The loss from discontinued operations attributable to the Company was $168.7 million compared to a loss of $798.8 million in the prior year. The decreased loss is primarily due to the completion of the sales of Company's exploration and production and refining businesses. The decreased loss was largely the result of the absence in 2016 of a noncash write-down of oil and natural gas properties of $315.3 million (after tax) and fair value impairments of the exploration and production business's assets held for sale of $475.4 million (after tax), as discussed in Item 8 - Note 2 , partially offset by a fair value impairment of the refining business of $156.7 million (after tax) in 2016, as discussed in Item 8 - Note 2 .

2015 compared to 2014 Discontinued operations attributable to the Company recognized a loss of $798.8 million compared to income of $113.2 million in the prior year. The decrease in income was primarily due to the marketing and sale of the Company's exploration and production business's assets. The decrease was largely the result of a noncash write-down of oil and natural gas properties of $315.3 million (after tax) and fair value impairments of the exploration and production business's assets held for sale of $475.4 million (after tax), as discussed in Item 8 - Note 2 , as well as decreased average realized commodity prices and decreased production.

Intersegment Transactions

Amounts presented in the preceding tables will not agree with the Consolidated Statements of Income due to the Company's elimination of intersegment transactions. The amounts relating to these items are as follows:

Years ended December 31,		2016		2015		2014
				(In millions)		
Intersegment transactions:						
Operating revenues	$	**57.4**	$	78.8	$	136.3
Purchased natural gas sold		**48.7**		48.9		44.7
Operation and maintenance		**8.7**		26.9		81.7
Income from continuing operations*		**(6.3)**		(5.0)		6.2

* Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.

For more information on intersegment eliminations, see Item 8 - Note 13 .

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.

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

Electric and natural gas distribution

- The Company expects to grow its rate base by approximately 4 percent annually over the next five years on a compound basis. This growth projection is on a much larger base, having grown rate base at a record pace of 12 percent compounded annually over the past five-year period. The utility operations are spread across eight states where customer growth is expected to be higher than the national average. This customer growth, along with system upgrades and replacements needed to supply safe and reliable service, will require investments in new electric generation and transmission, and electric and natural gas distribution. Rate base at December 31, 2016, was $1.9 billion.
- The Company expects its customer base to grow by 1.0 percent to 2.0 percent per year.
- In June 2016, the Company, along with a partner, began to build a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota, a distance of about 160 miles. The project has been approved as a MISO multivalue project. Approximately 97 percent of the necessary easements have been secured. The Company expects the project to be completed in 2019.
- The Company signed a 25-year agreement to purchase the power from a wind farm expansion in southwest North Dakota. The agreement also includes an option to buy the project at the close of construction. The expansion of the Thunder Spirit Wind farm will boost the combined production at the wind farm to approximately 150 MW of renewable energy and will increase the Company's nameplate generation portfolio from approximately 22 percent renewables to 27 percent. The original 107.5-MW Thunder Spirit Wind farm includes 43 turbines; it was purchased by the Company in December 2015. The expansion includes 13 to 16 turbines, depending on the turbine size selected. It is expected to be online in December 2018. If the Company buys the project, the capital will be incremental to the capital expenditures forecast. Construction costs for the project are estimated to be $85 million.
- The Company is in the process of completing its 2017 integrated resource plan and is evaluating its future generation and power supply portfolio options, including a large-scale resource. The plan will be finalized and will be required to be filed by mid-2017. Future resource requirements identified in the plan could require investment that would be incremental to the capital expenditures forecast.
- The Company is involved with a number of pipeline projects to enhance the reliability and deliverability of its system.
- The Company is focused on organic growth, while monitoring potential merger and acquisition opportunities.
- The Company is evaluating the final Clean Power Plan rule published by the EPA in October 2015, which requires existing fossil fuel-fired electric generation facilities to reduce carbon dioxide emissions. It is unknown at this time what each state will require for emissions limits or reductions from each of the Company's owned and jointly owned fossil fuel-fired electric generating units. In February 2016, the United States Supreme Court granted an application for a stay of the Clean Power Plan pending the outcome of legal challenges. The Company has not included capital expenditures in 2017 through 2019 for the potential compliance requirements of the Clean Power Plan.
- Regulatory actions

  <u>Completed Cases:</u>

  Since January 1, 2015, the Company has finalized rate increases totaling $56.8 million in annual revenue. This includes electric rate proceedings in Montana, North Dakota, South Dakota, Wyoming and before the FERC, and natural gas proceedings in Minnesota, Montana, North Dakota, Oregon, South Dakota, Washington and Wyoming. Cases recently completed were:

  - On April 29, 2016, the Company filed an application with the OPUC for a natural gas rate increase, as discussed in Item 8 - Note 16 .
  - On June 10, 2016, the Company filed an application for an increase in electric rates with the WYPSC, as discussed in Item 8 - Note 16 .
  - On December 2, 2016, the Company filed an application with the MTPSC requesting authority to implement gas and electric tax tracking adjustments, as discussed in Item 8 - Note 16 .
  - On September 1, 2016, and as amended on January 10, 2017, the Company submitted an update to its transmission formula rate under the MISO tariff, as discussed in Item 8 - Note 16 .

  <u>Pending Cases:</u>

  The Company is requesting rate increases totaling $55.4 million in annual revenue, which includes $43.6 million in implemented interim rates. Cases pending are:

  - On October 26, 2015, the Company filed an application with the NDPSC requesting a renewable resource cost adjustment rider, as discussed in Item 8 - Note 16 .
  - On October 26, 2015, the Company filed an application with the NDPSC for an update to the electric generation resource recovery rider, as discussed in Item 8 - Note 16 .

  - On November 25, 2015, the Company filed an application with the NDPSC for an update of its transmission cost adjustment rider for recovery of MISO-related charges and two transmission projects in North Dakota, as discussed in Item 8 - Note 16 .
  - On August 12, 2016, the Company filed an application with the IPUC for a natural gas rate increase, as discussed in Item 8 - Note 16 .
  - On October 14, 2016, the Company filed an application with the NDPSC for an electric rate increase, as discussed in Item 8 - Note 16 .
  - On December 2, 2016, the Company filed an application with the MTPSC requesting authority to implement gas and electric tax tracking adjustments, as previously discussed in the completed cases and in Item 8 - Note 16 .
  - On December 21, 2016, the Company filed an application with the MNPUC requesting authority to implement a gas utility infrastructure cost tariff, as discussed in Item 8 - Note 16 .

Pipeline and midstream

- In September 2016, the Company secured sufficient capacity commitments and started survey work on a 38-mile pipeline that will deliver natural gas supply to eastern North Dakota and far western Minnesota. The Valley Expansion project will connect the Viking Gas Transmission Company pipeline near Felton, Minnesota, to the Company's existing pipeline near Mapleton, North Dakota. Cost of the expansion is estimated at $55 million to $60 million. The project, which is designed to transport 40 MMcf of natural gas per day, is under the jurisdiction of the FERC. In October 2016, the Company received FERC approval on its pre-filing for the Valley Expansion project. With minor enhancements, the pipeline will be able to transport significantly more volume if required, based on capacity requested or as needed in the future as the region's demand grows. Following receipt of necessary permits and regulatory approvals, construction is expected to begin in early 2018 with completion expected in late 2018.
- The Company signed agreements to complete expansion projects, including the Charbonneau and Line Section 25 expansion project. The Charbonneau and Line Section 25 expansion project will include a new compression station as well as other compression modifications and is expected to be in service in the second quarter of 2017. In addition, the Company completed the North Badlands project, which includes a 4-mile loop of the Garden Creek pipeline segment and other ancillary facilities, and it was placed in service on August 1, 2016. The Northwest North Dakota project, which includes modification of existing compression, a new compression unit and re-cylindering, was put into service in June 2016.
- The Company continues to target profitable growth by means of both organic projects in areas of existing operations and by looking for potential acquisitions that fit existing expertise and capabilities.
- The Company is focused on improving existing operations and accelerating growth in its current markets while evaluating expansion into other basins.

Construction materials and contracting

- Approximate work backlog at December 31, 2016, was $538 million, compared to $491 million a year ago.
- Projected revenues are in the range of $1.85 billion to $1.95 billion in 2017.
- The Company anticipates margins in 2017 to be slightly higher compared to 2016 margins.
- In December 2015, a $305 billion, five-year federal highway bill was passed for funding of transportation infrastructure projects that are a key part of the construction materials market.
- As the country's fifth-largest sand and gravel producer, the Company will continue to strategically manage its 1.0 billion tons of aggregate reserves in all its markets, as well as take further advantage of being vertically integrated.

Construction services

- Approximate work backlog at December 31, 2016, was $475 million, compared to $493 million a year ago. The backlog includes transmission, distribution, substation, industrial, petrochemical, high technology, solar energy renewables, research and development, higher education, government, transportation, health care, hospitality, gaming, commercial, institutional and service work.
- Projected revenues are in the range of $1.0 billion to $1.1 billion in 2017.
- The Company anticipates margins in 2017 to be comparable to 2016 margins.
- The Company continues to pursue opportunities for expansion in energy projects, such as petrochemical, transmission, substations, utility services, and renewables. Initiatives are aimed at capturing additional market share and expanding into new markets.
- As the 13th-largest specialty contractor, the Company continues to pursue opportunities for expansion and execute initiatives in current and new markets that align with the Company's expertise, resources and strategic growth plan.

New Accounting Standards

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

Critical Accounting Policies Involving Significant Estimates

The Company has prepared its financial statements in conformity with GAAP. The preparation of these financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities, at the date of the financial statements as well as the reported amounts of revenues and expenses during the reporting period. The Company's significant accounting policies are discussed in Item 8 - Note 1 .

Estimates are used for items such as impairment testing of assets held for sale, long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; 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; and the valuation of stock-based compensation. 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 testing of assets held for sale

The Company evaluates disposal groups classified as held for sale based on the lower of carrying value or fair value less cost to sell. The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the first quarter of 2016, the estimated fair value of Fidelity's assets was determined using the market approach largely based on a purchase and sale agreement. In the second quarter of 2016, the fair value of Fidelity's assets was determined using the income and market approaches. The income approach was determined by using the present value of estimated future cash flows. The market approach was based on market transactions of similar properties. Also in the second quarter of 2016, the estimated fair value of Dakota Prairie Refining was determined using the market approach based on the sale transaction to Tesoro. In the fourth quarter of 2016, the estimated fair value of Pronghorn was determined using the market approach based on the purchase and sale agreement with Tesoro Logistics.

There is risk involved when determining the fair value of assets, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the assets could be different using different estimates and assumptions in the valuation techniques used.

The Company believes its estimates used in calculating the fair value of its assets held for sale are reasonable based on the information that is known when the estimates are made. For more information related to impairment testing of assets held for sale, see Item 8 - Note 2.

Impairment of long-lived assets and intangibles

The Company reviews the carrying values of its long-lived assets and intangibles, excluding assets held for sale, whenever events or changes in circumstances indicate that such carrying values may not be recoverable and at least annually for goodwill.

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

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Item 8 - Note 13 . The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2016 , 2015 , and 2014 , there were no significant impairment losses recorded. At December 31, 2016 , the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2016 . Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Long-Lived Assets Unforeseen events and changes in circumstances and market conditions and material differences in the value of long-lived assets and intangibles due to changes in estimates of future cash flows could negatively affect the fair value of the Company's assets and result in an impairment charge. If an impairment indicator exists for tangible and intangible assets, excluding goodwill, the asset group held and used is tested for recoverability by comparing an estimate of undiscounted future cash flows attributable to the assets compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value.

There is risk involved when determining the fair value of assets, tangible and intangible, as there may be unforeseen events and changes in circumstances and market conditions that have a material impact on the estimated amount and timing of future cash flows. In addition, the fair value of the asset could be different using different estimates and assumptions in the valuation techniques used.

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

Revenue recognition

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

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. 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. Changes in estimates could have a material effect on the Company's results of operations, financial position and cash flows.

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

The Company believes its estimates surrounding percentage-of-completion accounting are reasonable based on the information that is known when the estimates are made. The Company has contract administration, accounting and management control systems in place that allow its estimates to be updated and monitored on a regular basis. Because of the many factors that are evaluated in determining bid prices, it is inherent that the Company's estimates have changed in the past and will continually change in the future as new information becomes available for each job. There were no material changes in contract estimates at the individual contract level in 2016 .

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, actuarially determined mortality data, and health care 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 health care cost trend rates are determined by historical and future trends. The Company estimates that a 50 basis point decrease in the discount rate or in the expected return on plan assets would each increase expense by less than $1.3 million (after tax) for the year ended December 31, 2016 .

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 health care cost trend rates. The Company plans to continue to use its current methodologies to determine plan costs. For more information on the assumptions used in determining plan costs, see Item 8 - Note 14 .

Income taxes

Income taxes require significant judgments and estimates including the determination of income tax expense, deferred tax assets and liabilities and, if necessary, any valuation allowances that may be required for deferred tax assets and accruals for uncertain tax positions. The effective income tax rate is subject to variability from period to period as a result of changes in federal and state income tax rates and/or changes in tax laws. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states. The Company estimates that a one percent change in the effective tax rate would affect the income tax expense by less than $3.3 million for the year ended December 31, 2016 .

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.

Significant federal tax credit carryforwards and federal and state net operating loss carryforwards have been generated. The Company may not be able to utilize all of these carryforwards prior to their expiration. As a result, the Company has recorded valuation allowances for the amounts it may not be able to utilize. Changes in tax regulations or assumptions regarding current and future taxable income could require a change to the estimated valuation allowances in the future resulting in a material impact to the Company's financial position and results of operations. For more information related to federal and state net operating loss carryforwards, see Item 8 - Notes 2 and 11 .

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

Liquidity and Capital Commitments

At December 31, 2016 , the Company had cash and cash equivalents of $46.1 million and available capacity of $ 504.9 million under the outstanding credit facilities of the Company and its subsidiaries. The Company expects to meet its obligations for debt maturing within one year from various sources, including internally generated funds; the Company's credit facilities, as described later; and through the issuance of long-term debt.

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. Changes in cash flows for discontinued operations are related to the former exploration and production and refining businesses.

Cash flows provided by operating activities in 2016 decreased $199.6 million from 2015. The decrease in cash flows provided by operating activities was largely from lower cash flows at the exploration and production business. The decrease was also due to higher working capital requirements at the electric, natural gas distribution and pipeline and midstream businesses. Partially offsetting the decrease in cash flows provided by operating activities was higher cash flows from continuing operations (excluding working capital) at the electric, pipeline and midstream and construction materials and contracting businesses.

Cash flows provided by operating activities in 2015 increased $74.8 million from 2014. The increase was primarily due to lower working capital requirements of $232.2 million, primarily at the natural gas distribution business, largely related to lower natural gas sales and the construction services business, largely due to lower workloads; as well as lower income tax payments. Partially offsetting this increase was lower earnings primarily due to lower commodity prices at the exploration and production business.

Investing activities Cash flows used in investing activities in 2016 decreased $77.4 million from 2015 primarily due to lower capital expenditures largely at the electric and refining businesses. Partially offsetting this decrease is lower proceeds from the sale of properties at the exploration and production business.

Cash flows used in investing activities in 2015 decreased $521.7 million from 2014 primarily due to lower capital expenditures (including discontinued operations) and higher proceeds from the sale of properties, largely at the exploration and production business.

Financing activities Cash flows used in financing activities in 2016 decreased $60.8 million from 2015 primarily due to the lower repayment of long-term debt of $250.9 million, partially offset by debt repayment in connection with the sale of the refining business, lower capital contributions at the refining business and lower issuance of long-term debt of $36.9 million.

Cash flows used in financing activities was $255.7 million in 2015 compared to cash flows provided by financing activities of $325.2 million in 2014. The change was primarily due to the lower issuance of long-term debt of $260.2 million, higher repayment of long-term debt of $201.3 million and lower issuance of common stock.

Defined benefit pension plans

The Company has qualified noncontributory defined benefit 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, 2016 , the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $102.8 million . Pretax pension expense reflected in the years ended December 31, 2016 , 2015 and 2014 , was $2.1 million , $2.0 million and $1.1 million , respectively. The Company's pension expense is currently projected to be approximately $2.5 million to $3.5 million in 2017 . Funding for the pension plans is actuarially determined. The minimum required contributions for 2015 and 2014 were approximately $3.9 million and $10.8 million , respectively. There were no minimum required contributions for 2016. For more information on the Company's pension plans, see Item 8 - Note 14 .

Capital expenditures

The Company's capital expenditures from continuing operations for 2014 through 2016 and as anticipated for 2017 through 2019 are summarized in the following table.

	Actual (a)			Estimated		
	2014	2015	**2016**	2017	2018	2019
			(In millions)			
Capital expenditures:						
Electric	$ 185	$ 333	**$ 111**	$ 142	$ 140	$ 110
Natural gas distribution	121	131	**126**	135	134	147
Pipeline and midstream	62	18	**35**	41	57	120
Construction materials and contracting	38	48	**38**	43	55	46
Construction services	27	38	**60**	9	9	10
Other (b)	2	4	**2**	153	152	2
Total capital expenditures	$ 435	$ 572	**$ 372**	$ 523	$ 547	$ 435

(a) Capital expenditures for 2016, 2015 and 2014 include noncash capital expenditure-related accounts payable and AFUDC, totaling $(15.8) million, $35.3 million and $5.1 million, respectively.
(b) Other includes additional growth capital in 2017 and 2018 not allocated to a specific business unit.

The 2016 capital expenditures were met from internal sources and the issuance of long-term debt. Estimated capital expenditures for the years 2017 through 2019 include those for:

- System upgrades
- Routine replacements
- Service extensions
- Routine equipment maintenance and replacements
- Buildings, land and building improvements
- Pipeline, gathering and other midstream projects
- Power generation and transmission opportunities, including certain costs for additional electric generating capacity
- Environmental upgrades
- Other growth opportunities

The Company continues to evaluate potential future acquisitions and other growth opportunities; however, they are dependent upon the availability of economic opportunities and, as a result, capital expenditures may vary significantly from the estimates in the preceding table. It is anticipated that all of the funds required for capital expenditures for the years 2017 through 2019 will be met from various sources, including internally generated funds; the Company's credit facilities, as described later; through the issuance of long-term debt; and asset sales.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2016 . 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 more information on the covenants, certain other conditions and cross-default provisions, see Item 8 - Note 6 .

The following table summarizes the outstanding revolving credit facilities of the Company and its subsidiaries at December 31, 2016 :

Company	Facility		Facility Limit		Amount Outstanding		Letters of Credit		Expiration Date
					(In millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0		$ 111.0	(b)	$ —		5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement		$ 50.0	(c)	$ —		$ 2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement		$ 65.0	(e)	$ 20.9		$ —		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0		$ 151.0	(b)	$ —		9/23/21

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75.0 million .
(d) Outstanding letter(s) of credit reduce the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million .
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $600.0 million). There were no amounts outstanding under the credit agreement.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of the construction businesses.

The following includes information related to the preceding table.

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings. The Company's objective is to maintain acceptable credit ratings in order to access the capital markets through the issuance of commercial paper. Downgrades in the Company's credit ratings have not limited, nor are currently expected to limit, the Company's ability to access the capital markets. If the Company were to experience a downgrade of its credit ratings, it may need to borrow under its credit agreement and may experience an increase in overall interest rates with respect to its cost of borrowings.

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

The Company's coverage of fixed charges including preferred stock dividends was 3.9 times and 3.1 times for the 12 months ended December 31, 2016 and 2015 , respectively.

On November 21, 2016, the Company entered into a $100.0 million note purchase agreement. The Company issued $40.0 million of Senior Notes under the agreement on November 21, 2016, with a due date of November 21, 2046, at an interest rate of 4.15 percent. The Company contracted to issue an additional $60.0 million of Senior Notes under the agreement on March 21, 2017, with due dates ranging from March 2032 to March 2037 at a weighted average interest rate of 3.61 percent.

Total equity as a percent of total capitalization was 56 percent and 58 percent at December 31, 2016 and 2015 , respectively. This ratio is calculated as the Company's total equity, divided by the Company's total capital. Total capital is the Company's total debt, including short-term borrowings and long-term debt due within one year, plus total equity. This ratio indicates how a company is financing its operations, as well as its financial strength.

On May 20, 2013, the Company entered into an Equity Distribution Agreement with Wells Fargo Securities, LLC with respect to the issuance and sale of up to 7.5 million shares of the Company's common stock. The agreement terminated on February 28, 2016. The common stock was offered for sale, from time to time, in accordance with the terms and conditions of the agreement. Proceeds from the shares of common stock under the agreement were used for corporate development purposes and other general corporate purposes. Under the agreement, the Company did not issue any shares of stock between January 1, 2016 and February 28, 2016. Since inception of the Equity Distribution Agreement, the Company issued a cumulative total of 4.4 million shares of stock receiving net proceeds of $144.7 million through February 28, 2016.

Intermountain Gas Company On November 9, 2016, Intermountain issued $30.0 million of Senior Notes with a due date of November 9, 2046, at an interest rate of 4.0 percent.

Centennial Energy Holdings, Inc. On September 23, 2016, Centennial amended its revolving credit agreement to decrease the borrowing limit by $150.0 million to $500.0 million and extend the termination date to September 23, 2021. The credit agreement contains customary covenants and provisions, including a covenant of Centennial not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent. Other covenants include restricted payments, restrictions on the sale of certain assets, limitations on subsidiary indebtedness and the making of certain loans and investments.

Centennial's revolving credit agreement contains cross-default provisions. These provisions state that if Centennial or any subsidiary of Centennial fails to make any payment with respect to any indebtedness or contingent obligations, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, the revolving credit agreement will be in default.

Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued 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 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.

WBI Energy Transmission, Inc. On May 17, 2016, WBI Energy Transmission entered into an amendment to its amended and restated uncommitted note purchase and private shelf agreement to increase the aggregate issuance capacity from $175.0 million to $200.0 million and extend the issuance period to May 16, 2019. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2016 , which reduced capacity under this uncommitted private shelf agreement to $100.0 million. This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

Off balance sheet arrangements

In June 2016, WBI Energy sold all of the outstanding membership interests in Dakota Prairie Refining. In connection with the sale, Centennial agreed to continue to guarantee certain debt obligations of Dakota Prairie Refining which totaled $63.8 million at December 31, 2016 , and are expected to mature by 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining.

In March 2016, a sale agreement was signed to sell Fidelity's assets in the Paradox Basin. In connection with the sale, Centennial agreed to guarantee Fidelity's indemnity obligations associated with the Paradox Basin assets. The guarantee was required by the buyer as a condition to the sale of the Paradox Basin assets.

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

Contractual obligations and commercial commitments

For more information on the Company's contractual obligations on long-term debt, operating leases and purchase commitments, see Item 8 - Notes 6 and 17 . At December 31, 2016 , the Company's commitments under these obligations were as follows:

	2017	2018	2019	2020	2021	Thereafter	Total
				(In millions)			
Long-term debt	$ 43.6	$ 169.4	$ 162.2	$ 15.0	$ 151.0	$ 1,254.9	$ 1,796.1
Estimated interest payments*	77.4	74.5	65.2	62.7	61.3	543.0	884.1
Operating leases	51.7	43.3	33.9	23.2	9.4	42.0	203.5
Purchase commitments	367.7	215.7	189.4	138.0	130.6	859.5	1,900.9
	$ 540.4	$ 502.9	$ 450.7	$ 238.9	$ 352.3	$ 2,699.4	$ 4,784.6

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

At December 31, 2016 , the Company had total liabilities of $315.0 million related to asset retirement obligations that are excluded from the table above. Of the total asset retirement obligations, the current portion was $4.3 million at December 31, 2016 , and was included in other accrued liabilities on the Consolidated Balance Sheet. The remainder, which constitutes the long-term portion of asset retirement obligations, was included in other liabilities on the Consolidated Balance Sheet. Due to the nature of these obligations, the Company cannot determine precisely when the payments will be made to settle these obligations. For more information, see Item 8 - Note 7 .

The Company has no uncertain tax positions and no minimum funding requirements for its defined benefit pension plans for 2017 .

The Company's MEPP contributions are based on union employee payroll, which cannot be determined in advance for future periods. The Company may also be required to make additional contributions to its MEPPs as a result of their funded status. For more information, see Item 1A - Risk Factors and Item 8 - Note 14 .

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2016 , 2015 or 2014 .

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The Company is exposed to the impact of market fluctuations associated with interest rates. The Company has policies and procedures to assist in controlling these market risks and from time to time has utilized derivatives to manage a portion of its risk.

Interest rate risk

The Company uses fixed and variable rate long-term debt to partially finance capital expenditures and mandatory debt retirements. These debt agreements expose the Company to market risk related to changes in interest rates. The Company manages this risk by taking advantage of market conditions when timing the placement of long-term financing. The Company from time to time has utilized interest rate swap agreements to manage a portion of the Company's interest rate risk and may take advantage of such agreements in the future to minimize such risk.

At December 31, 2016 and 2015 , the Company had no outstanding interest rate hedges.

The following table shows the amount of debt, including current portion, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2016 .

	2017	2018	2019	2020	2021	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 43.6	$ 148.5	$ 51.2	$ 15.0	—	$ 1,254.9	$ 1,513.2	$ 1,559.0
Weighted average interest rate	6.3%	6.1%	4.3%	5.2%	—	4.8%	4.9%	—
Variable rate	—	$ 20.9	$ 111.0	—	$ 151.0	—	$ 282.9	$ 282.9
Weighted average interest rate	—	3.1%	1.1%	—	1.4%	—	1.4%	—

Item 8. Financial Statements and Supplementary Data

Management's Report on Internal Control Over Financial Reporting

The management of MDU Resources Group, Inc. is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934. The Company's internal control system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles in the United States of America.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2016 . In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework (2013)* .

Based on our evaluation under the framework in *Internal Control-Integrated Framework (2013)* , management concluded that the Company's internal control over financial reporting was effective as of December 31, 2016 .

The effectiveness of the Company's internal control over financial reporting as of December 31, 2016 , has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ David L. Goodin	/s/ Doran N. Schwartz
David L. Goodin President and Chief Executive Officer	Doran N. Schwartz Vice President and Chief Financial Officer

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2016 and 2015 , and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2016 . Our audits also included the financial statement schedules listed in the Index at Item 15. These consolidated financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedules based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the consolidated financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall consolidated financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of MDU Resources Group, Inc. and subsidiaries as of December 31, 2016 and 2015 , and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016 , in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2016 , based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 24, 2017 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2017

Report of Independent Registered Public Accounting Firm

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

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2016 , based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016 , based on the criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2016 of the Company and our report dated February 24, 2017 expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2017

Consolidated Statements of Income

Years ended December 31,		2016		2015		2014
		(In thousands, except per share amounts)				
Operating revenues:						
Electric, natural gas distribution and regulated pipeline and midstream	**$**	**1,141,454**	$	1,149,038	$	1,246,903
Nonregulated pipeline and midstream, construct ion materials and contracting, construction services and other		**2,987,374**		2,865,014		2,868,170
Total operating revenues		**4,128,828**		4,014,052		4,115,073
Operating expenses:						
Fuel and purchased power		**75,512**		86,238		89,312
Purchased natural gas sold		**382,753**		450,114		558,463
Operation and maintenance:						
Electric, natural gas distribution and regulated pipeline and midstream		**312,404**		278,171		269,175
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other		**2,580,895**		2,527,052		2,523,039
Depreciation, depletion and amortization		**216,318**		211,747		203,084
Taxes, other than income		**151,826**		140,955		144,818
Total operating expenses		**3,719,708**		3,694,277		3,787,891
Operating income		**409,120**		319,775		327,182
Other income		**4,956**		18,457		9,138
Interest expense		**87,848**		91,179		86,871
Income before income taxes		**326,228**		247,053		249,449
Income taxes		**93,132**		70,664		64,422
Income from continuing operations		**233,096**		176,389		185,027
Income (loss) from discontinued operations, net of tax (Note 2)		**(300,354)**		(834,080)		109,311
Net income (loss)		**(67,258)**		(657,691)		294,338
Loss from discontinued operations attributable to noncontrolling interest (Note 2)		**(131,691)**		(35,256)		(3,895)
Dividends declared on preferred stocks		**685**		685		685
Earnings (loss) on common stock	**$**	**63,748**	$	(623,120)	$	297,548
Earnings (loss) per common share - basic:						
Earnings before discontinued operations	**$**	**1.19**	$	.90	$	.96
Discontinued operations attributable to the Company, net of tax		**(.86)**		(4.10)		.59
Earnings (loss) per common share - basic	**$**	**.33**	$	(3.20)	$	1.55
Earnings (loss) per common share - diluted:						
Earnings before discontinued operations	**$**	**1.19**	$	.90	$	.96
Discontinued operations attributable to the Company, net of tax		**(.86)**		(4.10)		.59
Earnings (loss) per common share - diluted	**$**	**.33**	$	(3.20)	$	1.55
Weighted average common shares outstanding - basic		**195,299**		194,928		192,507
Weighted average common shares outstanding - diluted		**195,618**		194,986		192,587

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2016	2015	2014
		(In thousands)	
Net income (loss)	**$ (67,258)**	$ (657,691)	$ 294,338
Other comprehensive income (loss):			
Net unrealized gain on derivative instruments qualifying as hedges:			
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $226, $233 and $240 in 2016, 2015 and 2014, respectively	**367**	404	399
Reclassification adjustment for loss on derivative instruments included in income (loss) from discontinued operations, net of tax of $0, $0 and $173 in 2016, 2015 and 2014, respectively	**—**	—	295
Net unrealized gain on derivative instruments qualifying as hedges	**367**	404	694
Postretirement liability adjustment:			
Postretirement liability losses arising during the period, net of tax of $(836), $(55) and $(7,665) in 2016, 2015 and 2014, respectively	**(1,470)**	(88)	(12,409)
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of $1,425, $1,128 and $492 in 2016, 2015 and 2014, respectively	**2,506**	1,794	796
Reclassification of postretirement liability adjustment to regulatory asset, net of tax of $0, $1,416 and $4,509 in 2016, 2015 and 2014, respectively	**—**	2,255	7,202
Postretirement liability adjustment	**1,036**	3,961	(4,411)
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $31, $(105) and $(99) in 2016, 2015 and 2014, respectively	**51**	(173)	(162)
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss), net of tax of $0, $490 and $0 in 2016, 2015 and 2014, respectively	**—**	802	—
Foreign currency translation adjustment	**51**	629	(162)
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(98), $(91) and $(83) in 2016, 2015 and 2014, respectively	**(182)**	(170)	(154)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $77, $70 and $73 in 2016, 2015 and 2014, respectively	**143**	131	135
Net unrealized loss on available-for-sale investments	**(39)**	(39)	(19)
Other comprehensive income (loss)	**1,415**	4,955	(3,898)
Comprehensive income (loss)	**(65,843)**	(652,736)	290,440
Comprehensive loss from discontinued operations attributable to noncontrolling interest	**(131,691)**	(35,256)	(3,895)
Comprehensive income (loss) attributable to common stockholders	**$ 65,848**	$ (617,480)	$ 294,335

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

Consolidated Balance Sheets

December 31,	2016	2015
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 46,107	$ 83,903
Receivables, net	630,243	582,475
Inventories	238,273	240,551
Prepayments and other current assets	48,461	29,528
Current assets held for sale	14,391	54,847
Total current assets	977,475	991,304
Investments	125,866	119,704
Property, plant and equipment (Note 1)	6,510,229	6,387,702
Less accumulated depreciation, depletion and amortization	2,578,902	2,489,322
Net property, plant and equipment	3,931,327	3,898,380
Deferred charges and other assets:		
Goodwill (Note 3)	631,791	635,204
Other intangible assets, net (Note 3)	5,925	7,342
Other	415,419	351,603
Noncurrent assets held for sale	196,664	561,617
Total deferred charges and other assets	1,249,799	1,555,766
Total assets	$ 6,284,467	$ 6,565,154
Liabilities and Equity		
Current liabilities:		
Long-term debt due within one year	$ 43,598	$ 238,539
Accounts payable	279,962	286,061
Taxes payable	48,164	46,880
Dividends payable	37,767	36,784
Accrued compensation	65,867	45,192
Other accrued liabilities	184,377	167,322
Current liabilities held for sale	9,924	126,483
Total current liabilities	669,659	947,261
Long-term debt (Note 6)	1,746,561	1,557,624
Deferred credits and other liabilities:		
Deferred income taxes	668,226	663,629
Other	883,777	812,342
Noncurrent liabilities held for sale	—	63,750
Total deferred credits and other liabilities	1,552,003	1,539,721
Commitments and contingencies (Notes 14, 16 and 17)		
Equity:		
Preferred stocks (Note 8)	15,000	15,000
Common stockholders' equity:		
Common stock (Note 9) Authorized - 500,000,000 shares, $1.00 par value Issued - 195,843,297 shares in 2016 and 195,804,665 shares in 2015	195,843	195,805
Other paid-in capital	1,232,478	1,230,119
Retained earnings	912,282	996,355
Accumulated other comprehensive loss	(35,733)	(37,148)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,301,244	2,381,505
Total stockholders' equity	2,316,244	2,396,505
Noncontrolling interest	—	124,043
Total equity	2,316,244	2,520,548
Total liabilities and equity	$ 6,284,467	$ 6,565,154

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

Consolidated Statements of Equity

Years ended December 31, 2016, 2015 and 2014

	Preferred Stock		Common Stock					Treasury Stock			
	Shares	Amount	Shares	Amount	Other Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Shares	Amount	Noncontrolling Interest	Total
					(In thousands, except shares)						
Balance at December 31, 2013	150,000	$ 15,000	189,868,780	$ 189,869	$ 1,056,996	$ 1,603,130	$ (38,205)	(538,921)	$ (3,626)	$ 32,738	$ 2,855,902
Net income (loss)	—	—	—	—	—	298,233	—	—	—	(3,895)	294,338
Other comprehensive loss	—	—	—	—	—	—	(3,898)	—	—	—	(3,898)
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(137,851)	—	—	—	—	(137,851)
Stock-based compensation	—	—	—	—	6,191	—	—	—	—	—	6,191
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	326,122	326	(5,890)	—	—	—	—	—	(5,564)
Excess tax benefit on stock-based compensation	—	—	—	—	4,729	—	—	—	—	—	4,729
Issuance of common stock	—	—	4,559,910	4,560	145,162	—	—	—	—	—	149,722
Contribution from non-controlling interest	—	—	—	—	—	—	—	—	—	86,900	86,900
Balance at December 31, 2014	150,000	15,000	194,754,812	194,755	1,207,188	1,762,827	(42,103)	(538,921)	(3,626)	115,743	3,249,784
Net loss	—	—	—	—	—	(622,435)	—	—	—	(35,256)	(657,691)
Other comprehensive income	—	—	—	—	—	—	4,955	—	—	—	4,955
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(143,352)	—	—	—	—	(143,352)
Stock-based compensation	—	—	—	—	3,689	—	—	—	—	—	3,689
Net tax deficit on stock-based compensation	—	—	—	—	(1,606)	—	—	—	—	—	(1,606)
Issuance of common stock	—	—	1,049,853	1,050	20,848	—	—	—	—	—	21,898
Contribution from non-controlling interest	—	—	—	—	—	—	—	—	—	52,000	52,000
Distribution to non-controlling interest	—	—	—	—	—	—	—	—	—	(8,444)	(8,444)
Balance at December 31, 2015	150,000	15,000	195,804,665	195,805	1,230,119	996,355	(37,148)	(538,921)	(3,626)	124,043	2,520,548
Net income (loss)	—	—	—	—	—	64,433	—	—	—	(131,691)	(67,258)
Other comprehensive income	—	—	—	—	—	—	1,415	—	—	—	1,415
Dividends declared on preferred stocks	—	—	—	—	—	(685)	—	—	—	—	(685)
Dividends declared on common stock	—	—	—	—	—	(147,821)	—	—	—	—	(147,821)
Stock-based compensation	—	—	—	—	4,383	—	—	—	—	—	4,383
Net tax deficit on stock-based compensation	—	—	—	—	(1,663)	—	—	—	—	—	(1,663)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	38,632	38	(361)	—	—	—	—	—	(323)
Contribution from non-controlling interest	—	—	—	—	—	—	—	—	—	7,648	7,648
Balance at December 31, 2016	**150,000**	**$ 15,000**	**195,843,297**	**$ 195,843**	**$ 1,232,478**	**$ 912,282**	**$ (35,733)**	**(538,921)**	**$ (3,626)**	**$ —**	**$ 2,316,244**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2016	2015	2014
		(In thousands)	
Operating activities:			
Net income (loss)	**$ (67,258)**	$ (657,691)	$ 294,338
Income (loss) from discontinued operations, net of tax	**(300,354)**	(834,080)	109,311
Income from continuing operations	**233,096**	176,389	185,027
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**216,318**	211,747	203,084
Deferred income taxes	**(2,049)**	(25,356)	54,963
Excess tax benefit on stock-based compensation	**—**	—	(4,729)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(25,641)**	4,704	6,652
Inventories	**2,433**	2,265	(17,484)
Other current assets	**(17,925)**	60,182	(45,830)
Accounts payable	**7,039**	37,224	(47,092)
Other current liabilities	**36,146**	6,864	(17,252)
Other noncurrent changes	**(26,459)**	(10,240)	(18,144)
Net cash provided by continuing operations	**422,958**	463,779	299,195
Net cash provided by discontinued operations	**39,251**	198,053	287,867
Net cash provided by operating activities	**462,209**	661,832	587,062
Investing activities:			
Capital expenditures	**(388,183)**	(536,832)	(429,336)
Net proceeds from sale or disposition of property and other	**44,826**	54,569	28,899
Investments	**(1,396)**	1,515	(1,041)
Net cash used in continuing operations	**(344,753)**	(480,748)	(401,478)
Net cash provided by (used in) discontinued operations	**39,658**	98,295	(502,712)
Net cash used in investing activities	**(305,095)**	(382,453)	(904,190)
Financing activities:			
Repayment of short-term borrowings	**—**	—	(11,500)
Issuance of long-term debt	**309,064**	345,920	606,168
Repayment of long-term debt	**(315,647)**	(566,498)	(365,247)
Proceeds from issuance of common stock	**—**	21,898	150,060
Dividends paid	**(147,156)**	(142,835)	(136,712)
Excess tax benefit on stock-based compensation	**—**	—	4,729
Tax withholding on stock-based compensation	**(323)**	—	(5,564)
Net cash provided by (used in) continuing operations	**(154,062)**	(341,515)	241,934
Net cash provided by (used in) discontinued operations	**(40,852)**	85,785	83,262
Net cash provided by (used in) financing activities	**(194,914)**	(255,730)	325,196
Effect of exchange rate changes on cash and cash equivalents	**4**	(225)	(155)
Increase (decrease) in cash and cash equivalents	**(37,796)**	23,424	7,913
Cash and cash equivalents - beginning of year	**83,903**	60,479	52,566
Cash and cash equivalents - end of year	**$ 46,107**	$ 83,903	$ 60,479

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

Notes to Consolidated Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation

The abbreviations and acronyms used throughout are defined following the Notes to Consolidated Financial Statements. The consolidated financial statements of the Company include the accounts of the following businesses: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, construction services and other. The electric and natural gas distribution businesses, as well as a portion of the pipeline and midstream business, are regulated. Construction materials and contracting, construction services and the other businesses, as well as a portion of the pipeline and midstream business, are nonregulated. For further descriptions of the Company's businesses, see Note 13 . Intercompany balances and transactions have been eliminated in consolidation, except for certain transactions related to the Company's regulated operations in accordance with GAAP. The statements also include the ownership interests in the assets, liabilities and expenses of jointly owned electric generating facilities.

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

The Company's regulated businesses account for certain income and expense items under the provisions of regulatory accounting, which requires these businesses to defer as regulatory assets or liabilities certain items that would have otherwise been reflected as expense or income, respectively, based on the expected regulatory treatment in future rates. The expected recovery or flowback of these deferred items generally is based on specific ratemaking decisions or precedent for each item. Regulatory assets and liabilities are being amortized consistently with the regulatory treatment established by the FERC and the applicable state public service commissions. See Note 4 for more information regarding the nature and amounts of these regulatory deferrals.

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

Management has also evaluated the impact of events occurring after December 31, 2016 , up to the date of issuance of these consolidated financial statements.

On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. WBI Energy and Calumet each previously owned 50 percent of the Dakota Prairie Refining membership interests and were equal members in building and operating Dakota Prairie Refinery. To effectuate the sale, WBI Energy acquired Calumet's 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. The sale of Dakota Prairie Refining reduces the Company's risk by decreasing exposure to commodity prices.

In the second quarter of 2015, the Company began the marketing and sale process of Fidelity, with an anticipated sale to occur within one year. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. The sale of Fidelity was part of the Company's strategic plan to grow its capital investments in the remaining business segments and to focus on creating a greater long-term value.

The assets and liabilities for the Company's discontinued operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded. Unless otherwise indicated, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations. For more information on the Company's discontinued operations, see Note 2 .

Cash and cash equivalents

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

Accounts receivable and allowance for doubtful accounts

Accounts receivable consists primarily of trade receivables from the sale of goods and services which are recorded at the invoiced amount net of allowance for doubtful accounts, and costs and estimated earnings in excess of billings on uncompleted contracts. For more information, see Percentage-of-completion method in this note. The total balance of receivables past due 90 days or more was $29.2 million and $27.8 million at December 31, 2016 and 2015 , respectively.

The allowance for doubtful accounts is determined through a review of past due balances and other specific account data. Account balances are written off when management determines the amounts to be uncollectible. The Company's allowance for doubtful accounts at December 31, 2016 and 2015 , was $10.5 million and $9.8 million , respectively.

Inventories and natural gas in storage

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

	2016	2015
	(In thousands)	
Aggregates held for resale	**$ 115,471**	$ 115,854
Asphalt oil	**29,103**	36,498
Natural gas in storage (current)	**25,761**	21,023
Materials and supplies	**18,372**	16,997
Merchandise for resale	**16,437**	15,318
Other	**33,129**	34,861
Total	**$ 238,273**	$ 240,551

The remainder of natural gas in storage, which largely represents the cost of gas required to maintain pressure levels for normal operating purposes, was included in deferred charges and other assets - other and was $49.5 million and $49.1 million at December 31, 2016 and 2015 , respectively.

Investments

The Company's investments include the cash surrender value of life insurance policies, an insurance contract, mortgage-backed securities and U.S. Treasury securities. The Company measures its investment in the insurance contract at fair value with any unrealized gains and losses recorded on the Consolidated Statements of Income. The Company has not elected the fair value option for its mortgage-backed securities and U.S. Treasury securities and, as a result, the unrealized gains and losses on these investments are recorded in accumulated other comprehensive income (loss). For more information, see Notes 5 and 14 .

Property, plant and equipment

Additions to property, plant and equipment are recorded at cost. When regulated assets are retired, or otherwise disposed of in the ordinary course of business, the original cost of the asset is charged to accumulated depreciation. With respect to the retirement or disposal of all other assets the resulting gains or losses are recognized as a component of income. The Company is permitted to capitalize AFUDC on regulated construction projects and to include such amounts in rate base when the related facilities are placed in service. In addition, the Company capitalizes interest, when applicable, on certain construction projects associated with its other operations. The amount of AFUDC and interest capitalized for the years ended December 31 were as follows:

	2016	2015	2014
		(In thousands)	
Interest capitalized	**$ —**	$ 4,381	$ 7,046
AFUDC - borrowed	**$ 914**	$ 4,907	$ 3,023
AFUDC - equity	**$ 565**	$ 7,971	$ 5,803

Generally, property, plant and equipment are depreciated on a straight-line basis over the average useful lives of the assets, except for depletable aggregate reserves, which are depleted based on the units-of-production method. The Company collects removal costs for plant assets in regulated utility rates. These amounts are recorded as regulatory liabilities, which are included in other liabilities.

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

	2016	2015	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	**$ 1,036,373**	$ 1,003,173	39
Distribution	**398,382**	375,612	44
Transmission	**284,048**	255,842	57
Construction in progress	**62,212**	42,436	-
Other	**107,598**	109,085	14
Natural gas distribution:			
Distribution	**1,718,633**	1,624,645	46
Construction in progress	**19,934**	20,530	-
Other	**440,846**	431,406	18
Pipeline and midstream:			
Transmission	**490,143**	460,305	54
Gathering	**37,831**	37,831	20
Storage	**45,350**	44,011	62
Construction in progress	**16,507**	7,549	-
Other	**40,873**	40,168	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	**31,682**	158,949	19
Construction in progress	**13**	89	-
Other	**9,800**	9,827	10
Construction materials and contracting:			
Land	**94,625**	95,870	-
Buildings and improvements	**102,347**	96,864	19
Machinery, vehicles and equipment	**930,471**	937,084	12
Construction in progress	**16,181**	18,615	-
Aggregate reserves	**405,751**	404,995	*
Construction services:			
Land	**5,346**	5,025	-
Buildings and improvements	**26,693**	25,259	26
Machinery, vehicles and equipment	**132,217**	121,940	6
Other	**7,105**	11,055	4
Other:			
Land	**2,837**	2,837	-
Other	**46,431**	46,700	23
Less accumulated depreciation, depletion and amortization	**2,578,902**	2,489,322	
Net property, plant and equipment	**$ 3,931,327**	$ 3,898,380	

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

Impairment of long-lived assets

The Company reviews the carrying values of its long-lived assets, excluding goodwill and assets held for sale, whenever events or changes in circumstances indicate that such carrying values may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted future cash flows attributable to the assets, compared to the carrying value of the assets. If impairment has occurred, the amount of the impairment recognized is determined by estimating the fair value of the assets and recording a loss if the carrying value is greater than the fair value. In the third quarter of 2015 , the Company recognized an impairment of $14.1 million (before tax), largely related to the sale of certain non-strategic natural gas gathering assets that were written down to their estimated fair value that was determined using the market approach. In the second quarter of 2015 , the Company recognized an impairment of $3.0 million (before tax) related to coalbed natural gas gathering assets located in Wyoming where there had been continued decline in natural gas development and production activity due to low natural gas prices. The coalbed natural gas gathering assets were written down to their estimated fair value that was determined using the income approach. The impairments are recorded in operation and maintenance expense on the Consolidated Statements of Income. For more information on these nonrecurring fair value measurements, see Note 5 .

No significant impairment losses were recorded in 2016, other than those related to the Company's assets held for sale and discontinued operations. For more information regarding these impairments, see Note 2 .

Unforeseen events and changes in circumstances could require the recognition of impairment losses at some future date.

Goodwill

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

The goodwill impairment test is a two-step process performed at the reporting unit level. The Company has determined that the reporting units for its goodwill impairment test are its operating segments, or components of an operating segment, that constitute a business for which discrete financial information is available and for which segment management regularly reviews the operating results. For more information on the Company's operating segments, see Note 13 . The first step of the impairment test involves comparing the fair value of each reporting unit to its carrying value. If the fair value of a reporting unit exceeds its carrying value, the test is complete and no impairment is recorded. If the fair value of a reporting unit is less than its carrying value, step two of the test is performed to determine the amount of impairment loss, if any. The impairment is computed by comparing the implied fair value of the reporting unit's goodwill to the carrying value of that goodwill. If the carrying value is greater than the implied fair value, an impairment loss must be recorded. For the years ended December 31, 2016 , 2015 and 2014 , there were no significant impairment losses recorded. At December 31, 2016 , the fair value substantially exceeded the carrying value at all reporting units.

Determining the fair value of a reporting unit requires judgment and the use of significant estimates which include assumptions about the Company's future revenue, profitability and cash flows, amount and timing of estimated capital expenditures, inflation rates, weighted average cost of capital, operational plans, and current and future economic conditions, among others. The fair value of each reporting unit is determined using a weighted combination of income and market approaches. The Company uses a discounted cash flow methodology for its income approach. Under the income approach, the discounted cash flow model determines fair value based on the present value of projected cash flows over a specified period and a residual value related to future cash flows beyond the projection period. Both values are discounted using a rate which reflects the best estimate of the weighted average cost of capital at each reporting unit. The weighted average cost of capital, which varies by reporting unit and is in the range of 5 percent to 9 percent, and a long-term growth rate projection of approximately 3 percent were utilized in the goodwill impairment test performed in the fourth quarter of 2016 . Under the market approach, the Company estimates fair value using multiples derived from comparable sales transactions and enterprise value to EBITDA for comparative peer companies for each respective reporting unit. These multiples are applied to operating data for each reporting unit to arrive at an indication of fair value. In addition, the Company adds a reasonable control premium when calculating the fair value utilizing the peer multiples, which is estimated as the premium that would be received in a sale in an orderly transaction between market participants. The Company believes that the estimates and assumptions used in its impairment assessments are reasonable and based on available market information, but variations in any of the assumptions could result in materially different calculations of fair value and determinations of whether or not an impairment is indicated.

Revenue recognition

Revenue is recognized when the earnings process is complete, as evidenced by an agreement between the customer and the Company, when delivery has occurred or services have been rendered, when the fee is fixed or determinable and when collection is reasonably assured. The Company recognizes utility revenue each month based on the services provided to all utility customers during the month. Accrued unbilled revenue which is included in receivables, net, represents revenues recognized in excess of amounts billed. Accrued unbilled revenue at Montana-Dakota, Cascade and Intermountain was $117.7 million and $102.1 million at December 31, 2016 and 2015 , respectively. The Company recognizes construction contract revenue at its construction businesses using the percentage-of-completion method as discussed later. The Company recognizes all other revenues when services are rendered or goods are delivered. The Company presents revenues net of taxes collected from customers at the time of sale to be remitted to governmental authorities, including sales and use taxes.

Percentage-of-completion method

The Company recognizes construction contract revenue from fixed-price and modified fixed-price construction contracts at its construction businesses using the percentage-of-completion method, measured by the percentage of costs incurred to date to estimated total costs for each contract. If a loss is anticipated on a contract, the loss is immediately recognized.

Costs and estimated earnings in excess of billings on uncompleted contracts represent revenues recognized in excess of amounts billed and were included in receivables, net. Billings in excess of costs and estimated earnings on uncompleted contracts represent billings in excess of revenues recognized and were included in accounts payable. Costs and estimated earnings in excess of billings and billings in excess of costs and estimated earnings on uncompleted contracts at December 31 were as follows:

	2016	2015
	(In thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 64,558	$ 64,369
Billings in excess of costs and estimated earnings on uncompleted contracts	$ 64,832	$ 68,048

Amounts representing balances billed but not paid by customers under retainage provisions in contracts at December 31 were as follows:

	2016	2015
	(In thousands)	
Short-term retainage*	$ 45,109	$ 46,207
Long-term retainage**	1,506	1,605
Total retainage	$ 46,615	$ 47,812

* Expected to be paid within one year or less and included in receivables, net.
** Included in deferred charges and other assets - other.

Asset retirement obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When the liability is initially recorded, the Company capitalizes a cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period, and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, the Company either settles the obligation for the recorded amount or incurs a gain or loss at its nonregulated operations or incurs a regulatory asset or liability at its regulated operations. For more information on asset retirement obligations, see Note 7 .

Legal costs

The Company expenses external legal fees as they are incurred.

Natural gas costs recoverable or refundable through rate adjustments

Under the terms of certain orders of the applicable state public service commissions, the Company is deferring natural gas commodity, transportation and storage costs that are greater or less than amounts presently being recovered through its existing rate schedules. Such orders generally provide that these amounts are recoverable or refundable through rate adjustments which are filed annually. Natural gas costs refundable through rate adjustments were $25.6 million and $20.9 million at December 31, 2016 and 2015 , respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $2.2 million and $547,000 at December 31, 2016 and 2015 , respectively, which is included in prepayments and other current assets.

Income taxes

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

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

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

Earnings (loss) per common share

Basic earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the weighted average number of shares of common stock outstanding during the year. Diluted earnings (loss) per common share were computed by dividing earnings (loss) on common stock by the total of the weighted average number of shares of common stock outstanding during the year, plus the effect of outstanding performance share awards. In 2016, 2015 and 2014, there were no shares excluded from the calculation of diluted earnings per share. Common stock outstanding includes issued shares less shares held in treasury. Net income (loss) was the same for both the basic and diluted earnings (loss) per share calculations. A reconciliation of the weighted average common shares outstanding used in the basic and diluted earnings (loss) per share calculation was as follows:

	2016	2015	2014
		(In thousands)	
Weighted average common shares outstanding - basic	**195,299**	194,928	192,507
Effect of dilutive performance share awards	**319**	58	80
Weighted average common shares outstanding - diluted	**195,618**	194,986	192,587
Shares excluded from the calculation of diluted earnings per share	**—**	—	—

Use of estimates

The preparation of financial statements in conformity with GAAP requires the Company to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements, as well as the reported amounts of revenues and expenses during the reporting period. Estimates are used for items such as impairment testing of assets held for sale, long-lived assets and goodwill; fair values of acquired assets and liabilities under the acquisition method of accounting; 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; and the valuation of stock-based compensation. 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.

New accounting standards

Revenue from Contracts with Customers In May 2014, the FASB issued guidance on accounting for revenue from contracts with customers. The guidance provides for a single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry specific guidance. This guidance was to be effective for the Company on January 1, 2017. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance one year and allowing entities to early adopt. With this decision, the guidance will be effective for the Company on January 1, 2018. Entities will have the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified approach, an entity would recognize the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption. In addition, the modified approach will require additional disclosures. The Company is planning to adopt the guidance using the modified retrospective approach and continues to evaluate the effects it will have on its results of operations, financial position, cash flows and disclosures.

Simplifying the Presentation of Debt Issuance Costs In April 2015, the FASB issued guidance on simplifying the presentation of debt issuance costs in the financial statements. This guidance requires entities to present debt issuance costs as a direct deduction to the related debt liability. The amortization of these costs will be reported as interest expense. The guidance was effective for the Company on January 1, 2016, and was to be applied retrospectively. Early adoption of this guidance was permitted, however the Company did not elect to do so. The guidance required a reclassification of the debt issuance costs on the Consolidated Balance Sheets, but did not impact the Company's results of operations or cash flows. As a result of the retrospective application of this change in accounting principle, the Company reclassified debt issuance costs of $100,000 from prepayments and other current assets and $6.0 million from deferred charges and other assets - other to long-term debt on its Consolidated Balance Sheets at December 31, 2015.

Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent) In May 2015, the FASB issued guidance on fair value measurement and disclosure requirements removing the requirement to include investments in the fair value hierarchy for which fair value is measured using the net asset value per share practical expedient. The new guidance also removes the requirement to make certain disclosures for all investments that are eligible to be measured at net asset value using the practical expedient, and rather limits those disclosures to investments for which the practical expedient has been elected. This guidance was effective for the Company on January 1, 2016, with early adoption permitted. The application of this guidance affected the Company's disclosures; however, it did not impact the Company's results of operations, financial position or cash flows.

Simplifying the Measurement of Inventory In July 2015, the FASB issued guidance regarding inventory that is measured using the first-in, first-out or average cost method. The guidance does not apply to inventory measured using the last-in, first-out or the retail inventory method. The guidance requires inventory within its scope to be measured at the lower of cost or net realizable value, which is the estimated selling price in the normal course of business less reasonably predictable costs of completion, disposal and transportation. These amendments more closely align GAAP with IFRS. This guidance was effective for the Company on January 1, 2017, on a prospective basis. The Company does not anticipate the guidance will have a material effect on its results of operations, financial position or cash flows.

Balance Sheet Classification of Deferred Taxes In November 2015, the FASB issued guidance regarding the classification of deferred taxes on the balance sheet. The guidance will require all deferred tax assets and liabilities to be classified as noncurrent. These amendments will align GAAP with IFRS. Entities had the option to apply the guidance prospectively, for all deferred tax assets and liabilities, or retrospectively. The Company adopted the guidance in the fourth quarter of 2016 and applied the retrospective method of adoption. The guidance required a reclassification of current deferred income taxes to noncurrent deferred income taxes on the Consolidated Balance Sheets, but did not impact the Company's results of operations or cash flows. As a result of the retrospective application of this change in accounting principle, the Company reclassified deferred income taxes of $33.1 million from current assets - deferred income taxes to deferred credits and other liabilities - deferred income taxes on its Consolidated Balance Sheets at December 31, 2015.

Recognition and Measurement of Financial Assets and Financial Liabilities In January 2016, the FASB issued guidance regarding the classification and measurement of financial instruments. The guidance revises the way an entity classifies and measures investments in equity securities, the presentation of certain fair value changes for financial liabilities measured at fair value and amends certain disclosure requirements related to the fair value of financial instruments. This guidance will be effective for the Company on January 1, 2018, with early adoption of certain amendments permitted. The guidance should be applied using a modified retrospective approach with the exception of equity securities without readily determinable fair values which will be applied prospectively. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a liability to make lease payments and a right-of-use asset representing its right to use the underlying asset for the lease term on the statement of financial position for leases with terms of more than 12 months. This guidance also requires additional disclosures. This guidance will be effective for the Company on January 1, 2019, and should be applied using a modified retrospective approach with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

Improvements to Employee Share-Based Payment Accounting In March 2016, the FASB issued guidance regarding simplification of several aspects of the accounting for share-based payment transactions. The guidance will affect the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows and calculation of dilutive shares. Certain amendments of this guidance are to be applied retrospectively and others prospectively. The Company adopted the guidance on January 1, 2017. All amendments in the guidance that apply to the Company were adopted on a prospective basis resulting in no adjustments being made to retained earnings. The Company anticipates the guidance will impact the Consolidated Statements of Income and the Consolidated Balance Sheets, as well as the dilutive earnings per share calculation, on a prospective basis with all taxes related to share-based payments recognized as income tax expense or benefit and no longer recognized in additional paid-in capital. The Company anticipates the guidance will not have a material impact on its cash flows.

Classification of Certain Cash Receipts and Cash Payments In August 2016, the FASB issued guidance to clarify the classification of certain cash receipts and payments in the statement of cash flows. The guidance is intended to standardize the presentation and classification of certain transactions, including cash payments for debt prepayment or extinguishment, proceeds from insurance claim settlements and distributions from equity method investments. In addition, the guidance clarifies how to classify transactions that have characteristics of more than one class of cash flows. This guidance will be effective for the Company on January 1, 2018, with early adoption permitted. An entity that elects early adoption must adopt all the amendments in the same period and apply any adjustments as of the beginning of the fiscal year. Entities must apply the guidance retrospectively unless it is impracticable to do so, in which case they may apply it prospectively as of the earliest date practicable. The Company is evaluating the effects the adoption of the new guidance will have on its cash flows and disclosures.

Clarifying the Definition of a Business In January 2017, the FASB issued guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions or disposals of assets or businesses. The guidance provides a screen to determine when an integrated set of assets and activities is not a business. The guidance will also affect other aspects of accounting, such as determining reporting units for goodwill testing. The guidance will be effective for the Company on January 1, 2018, and should be applied on a prospective basis with early adoption permitted for transactions that occur before the issuance or effective date of the amendments and only when the transactions have not been reported in the financial statements or made available for issuance. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

Simplifying the Test for Goodwill Impairment In January 2017, the FASB issued guidance on simplifying the test for goodwill impairment by eliminating Step 2, which required an entity to measure the amount of impairment loss by comparing the implied fair value of reporting unit goodwill with the carrying amount of such goodwill. This guidance requires entities to perform a quantitative impairment test, previously Step 1, to identify both the existence of impairment and the amount of impairment loss by comparing the fair value of a reporting unit to its carrying amount. Entities will continue to have the option of performing a qualitative assessment to determine if the quantitative impairment test is necessary. The guidance also requires additional disclosures if an entity has one or more reporting units with zero or negative carrying amounts of net assets. The guidance will be effective for the Company on January 1, 2020, and should be applied on a prospective basis with early adoption permitted. The Company is evaluating the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. GAAP provides a framework for identifying VIEs and determining when a company should include the assets, liabilities, noncontrolling interest and results of activities of a VIE in its consolidated financial statements.

A VIE should be consolidated if a party with an ownership, contractual or other financial interest in the VIE (a variable interest holder) has the power to direct the VIE's most significant activities and the obligation to absorb losses or right to receive benefits of the VIE that could be significant to the VIE. A variable interest holder that consolidates the VIE is called the primary beneficiary. Upon consolidation, the primary beneficiary generally must initially record all of the VIE's assets, liabilities and noncontrolling interests at fair value and subsequently account for the VIE as if it were consolidated.

The Company's evaluation of whether it qualifies as the primary beneficiary of a VIE involves significant judgments, estimates and assumptions and includes a qualitative analysis of the activities that most significantly impact the VIE's economic performance and whether the Company has the power to direct those activities, the design of the entity, the rights of the parties and the purpose of the arrangement.

Comprehensive income (loss)

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

The after-tax changes in the components of accumulated other comprehensive loss as of December 31, 2016 , 2015 and 2014 , were as follows:

	Net Unrealized Gain (Loss) on Derivative Instruments Qualifying as Hedges	Post-retirement Liability Adjustment	Foreign Currency Translation Adjustment	Net Unrealized Gain (Loss) on Available-for-sale Investments	Total Accumulated Other Comprehensive Loss
			(In thousands)		
Balance at December 31, 2014	$ (3,071)	$ (38,218)	$ (829)	$ 15	$ (42,103)
Other comprehensive income (loss) before reclassifications	—	(88)	(173)	(170)	(431)
Amounts reclassified from accumulated other comprehensive loss	404	1,794	802	131	3,131
Amounts reclassified from accumulated other comprehensive loss to a regulatory asset	—	2,255	—	—	2,255
Net current-period other comprehensive income (loss)	404	3,961	629	(39)	4,955
Balance at December 31, 2015	(2,667)	(34,257)	(200)	(24)	(37,148)
Other comprehensive income (loss) before reclassifications	—	(1,470)	51	(182)	(1,601)
Amounts reclassified from accumulated other comprehensive loss	367	2,506	—	143	3,016
Net current-period other comprehensive income (loss)	367	1,036	51	(39)	1,415
Balance at December 31, 2016	**$ (2,300)**	**$ (33,221)**	**$ (149)**	**$ (63)**	**$ (35,733)**

Reclassifications out of accumulated other comprehensive loss for the years ended December 31 were as follows:

	2016	2015	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income (loss):			
Interest rate derivative instruments	**$ (593)**	$ (637)	Interest expense
	226	233	Income taxes
	(367)	(404)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	**(3,931)**	(2,922)	(a)
	1,425	1,128	Income taxes
	(2,506)	(1,794)	
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss)	**—**	(1,292)	Other income
	—	490	Income taxes
	—	(802)	
Reclassification adjustment for loss on available-for-sale investments included in net income (loss)	**(220)**	(201)	Other income
	77	70	Income taxes
	(143)	(131)	
Total reclassifications	**$ (3,016)**	$ (3,131)	

(a) Included in net periodic benefit cost (credit). For more information, see Note 14 .

Note 2 - Assets Held for Sale and Discontinued Operations

Assets held for sale

The assets and liabilities of Pronghorn have been classified as held for sale. Pronghorn's results of operations are included in the pipeline and midstream segment. The Company's consolidated financial statements and accompanying notes for the current period reflect Pronghorn classified as held for sale.

Pronghorn On November 21, 2016, WBI Energy Midstream announced it had entered into a purchase and sale agreement to sell its 50 percent non-operating ownership interest in Pronghorn to Tesoro Logistics. The transaction closed on January 1, 2017. The sale of Pronghorn further reduces the Company's risk exposure to commodity prices.

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale associated with Pronghorn on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2016
	(In thousands)
Assets	
Current assets:	
Prepayments and other current assets	**$ 68**
Total current assets held for sale	**68**
Noncurrent assets:	
Net property, plant and equipment	**93,424**
Goodwill	**9,737**
Less allowance for impairment of assets held for sale	**2,311**
Total noncurrent assets held for sale	**100,850**
Total assets held for sale	**$ 100,918**

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the fourth quarter of 2016, the fair value assessment was determined using the market approach based on the purchase and sale agreement with Tesoro Logistics. The fair value assessment indicated an impairment based on the carrying value exceeding the fair value, which resulted in the Company recording an impairment of $2.3 million ($1.4 million after tax) in the quarter ended December 31, 2016. The fair value of Pronghorn's assets has been categorized as Level 3 in the fair value hierarchy. The impairment was recorded in operation and maintenance expense on the Consolidated Statement of Income.

Discontinued operations

The assets and liabilities of the Company's discontinued operations have been classified as held for sale and the results of operations are shown in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. The Company's consolidated financial statements and accompanying notes for current and prior periods have been restated. At the time the assets were classified as held for sale, depreciation, depletion and amortization expense was no longer recorded.

Dakota Prairie Refining On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. WBI Energy and Calumet each previously owned 50 percent of the Dakota Prairie Refining membership interests and were equal members in building and operating Dakota Prairie Refinery. To effectuate the sale, WBI Energy acquired Calumet's 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. The sale of Dakota Prairie Refining reduces the Company's risk by decreasing exposure to commodity prices.

The Company retained certain liabilities of Dakota Prairie Refining which are reflected in current liabilities held for sale on the Consolidated Balance Sheet at December 31, 2016. Centennial continues to guarantee certain debt obligations of Dakota Prairie Refining; however, Tesoro has agreed to indemnify Centennial for any losses and litigation expenses arising for the guarantee. For more information related to the guarantee, see Note 17 .

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale related to the operations of and activity associated with Dakota Prairie Refining on the Company's Consolidated Balance Sheets at December 31 were as follows:

	2016	2015
	(In thousands)	
Assets		
Current assets:		
Cash and cash equivalents	**$ —**	$ 688
Receivables, net	**—**	7,693
Inventories	**—**	13,176
Income taxes receivable	**13,987**	2,495
Prepayments and other current assets	**—**	6,214
Total current assets held for sale	**13,987**	30,266
Noncurrent assets:		
Net property, plant and equipment	**—**	412,717
Other	**—**	9,627
Total noncurrent assets held for sale	**—**	422,344
Total assets held for sale	**$ 13,987**	$ 452,610
Liabilities		
Current liabilities:		
Short-term borrowings	**$ —**	$ 45,500
Long-term debt due within one year	**—**	5,250
Accounts payable	**7,425**	24,468
Taxes payable	**—**	1,391
Accrued compensation	**—**	938
Other accrued liabilities	**—**	4,953
Total current liabilities held for sale	**7,425**	82,500
Noncurrent liabilities:		
Long-term debt	**—**	63,750
Deferred income taxes	**14** (a)	23,841 (a)
Total noncurrent liabilities held for sale	**14**	87,591
Total liabilities held for sale	**$ 7,439**	$ 170,091

(a) On the Company's Consolidated Balance Sheets, these amounts were reclassified to noncurrent deferred income tax assets and are reflected in noncurrent assets held for sale.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2016, the fair value assessment was determined using the market approach based on the sale transaction to Tesoro. The fair value assessment indicated an impairment based on the carrying value exceeding the fair value, which resulted in the Company recording an impairment of $251.9 million ($156.7 million after tax) in the quarter ended June 30, 2016. The impairment was included in operating expenses from discontinued operations. The fair value of Dakota Prairie Refining's assets have been categorized as Level 3 in the fair value hierarchy. At December 31, 2016, the Company has not incurred any material exit and disposal costs related to Dakota Prairie Refining, and does not expect to incur any material exit and disposal costs.

Fidelity In the second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's oil and natural gas assets. The completion of the majority of these sales occurred between October 2015 and April 2016. The sale of Fidelity was part of the Company's strategic plan to grow its capital investments in the remaining business segments and to focus on creating a greater long-term value.

The carrying amounts of the major classes of assets and liabilities that are classified as held for sale related to the operations of Fidelity on the Company's Consolidated Balance Sheets at December 31 were as follows:

		2016		2015
		(In thousands)		
Assets				
Current assets:				
Receivables, net	**$**	**355**	$	13,387
Inventories		**—**		1,308
Income taxes receivable		**—**		9,665
Prepayments and other current assets		**—**		221
Total current assets held for sale		**355**		24,581
Noncurrent assets:				
Investments		**—**		37
Net property, plant and equipment		**5,507**		793,422
Deferred income taxes		**91,098**		124,035
Other		**161**		161
Less allowance for impairment of assets held for sale		**938**		754,541
Total noncurrent assets held for sale		**95,828**		163,114
Total assets held for sale	**$**	**96,183**	$	187,695
Liabilities				
Current liabilities:				
Accounts payable	**$**	**141**	$	25,013
Taxes payable		**19** (a)		1,052
Accrued compensation		**—**		13,080
Other accrued liabilities		**2,358**		4,838
Total current liabilities held for sale		**2,518**		43,983
Total liabilities held for sale	**$**	**2,518**	$	43,983

(a) On the Company's Consolidated Balance Sheets, this amount was reclassified to prepayments and other current assets and is reflected in current assets held for sale.

At December 31, 2016 and 2015, the Company's deferred tax assets included in assets held for sale were largely comprised of $89.3 million and $78.9 million , respectively, of federal and state net operating loss carryforwards.

The Company had federal income tax net operating loss carryforwards of $297.2 million and $208.2 million at December 31, 2016 and 2015, respectively. At December 31, 2016 and 2015, the Company had various state income tax net operating loss carryforwards of $189.1 million and $201.4 million , respectively. The federal net operating loss carryforwards expire in 2036 and 2037 if not utilized. The state net operating loss carryforwards are due to expire between 2023 and 2037. It is likely a portion of the benefit from the state carryforwards will not be realized; therefore, valuation allowances of $500,000 and $300,000 have been provided in 2016 and 2015, respectively.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. In the second quarter of 2016, the fair value assessment was determined using the income and market approaches. The income approach was determined by using the present value of future estimated cash flows. The market approach was based on market transactions of similar properties. The estimated carrying value exceeded the fair value and the Company recorded an impairment of $900,000 ($600,000 after tax) in the second quarter of 2016. In the first quarter of 2016, the fair value assessment was determined using the market approach largely based on a purchase and sale agreement. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of $1.4 million ($900,000 after tax) in the first quarter of 2016. In the second quarter of 2015, the estimated fair value was determined using the income and the market approaches. The income approach was determined by using the present value of future estimated cash flows. The income approach considered management's views on current operating measures as well as assumptions pertaining to market forces in the oil and gas industry including estimated reserves, estimated prices, market differentials, estimates of well operating and future development costs and timing of operations. The estimated cash flows were discounted using a rate believed to be consistent with those used by principal market participants. The market approach was provided by a third party and based on market transactions involving similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity's assets at June 30, 2015, and recording an impairment of $400.0 million ($252.0 million after tax) during the second quarter of 2015. In the third quarter of 2015, the estimated fair value of Fidelity was determined by agreed upon pricing in the purchase and sale agreements for the assets subject to the agreements, the majority of which closed during the fourth quarter of 2015, including customary purchase price adjustments. The values received in the bid proposals were lower than originally anticipated due to lower commodity prices than those projected in the second quarter of 2015. For those assets for which a purchase and sale agreement had not been entered into at that time, the fair value was based on the market approach utilizing multiples based on similar interests in oil and natural gas properties. The fair value assessment indicated an impairment based on the carrying value exceeding the estimated fair value, which resulted in the Company writing down Fidelity's assets at September 30, 2015, and recording an impairment of $356.1 million ($224.4 million after tax). In the fourth quarter of 2015, the fair value assessment was determined using the market approach based on purchase and sale agreements. The estimated fair value exceeded the carrying value and the Company recorded an impairment reversal of $1.6 million ($1.0 million after tax) in the fourth quarter of 2015. The impairments were included in operating expenses from discontinued operations. The estimated fair value of Fidelity's assets have been categorized as Level 3 in the fair value hierarchy.

The Company incurred transaction costs of approximately $300,000 in the first quarter of 2016 and $2.5 million in 2015. In addition to the transaction costs, and due in part to the change in plans to sell the assets of Fidelity rather than sell Fidelity as a company, Fidelity incurred and expensed approximately $5.6 million of exit and disposal costs in 2016, and has incurred $10.5 million of exit and disposal costs to date. The Company does not expect to incur any additional material exit and disposal costs. The exit and disposal costs are associated with severance and other related matters and exclude the office lease expiration discussed in the following paragraph.

Fidelity vacated its office space in Denver, Colorado. The Company incurred lease payments of approximately $900,000 in 2016. Lease termination payments of $3.2 million and $3.3 million were made during the second quarter of 2016 and fourth quarter of 2015, respectively. Existing office furniture and fixtures were relinquished to the lessor in the second quarter of 2016.

Historically, the Company used the full-cost method of accounting for its oil and natural gas production activities. Under this method, all costs incurred in the acquisition, exploration and development of oil and natural gas properties are capitalized and amortized on the units-of-production method based on total proved reserves.

Prior to the oil and natural gas properties being classified as held for sale, capitalized costs were subject to a "ceiling test" that limits such costs to the aggregate of the present value of future net cash flows from proved reserves discounted at 10 percent, as mandated under the rules of the SEC, plus the cost of unproved properties not subject to amortization, plus the effects of cash flow hedges, less applicable income taxes. Proved reserves and associated future cash flows are determined based on SEC Defined Prices and exclude cash outflows associated with asset retirement obligations that have been accrued on the balance sheet. If capitalized costs, less accumulated amortization and related deferred income taxes, exceed the full-cost ceiling at the end of any quarter, a permanent noncash write-down is required to be charged to earnings in that quarter regardless of subsequent price changes.

The Company's capitalized cost under the full-cost method of accounting exceeded the full-cost ceiling at March 31, 2015. SEC Defined Prices, adjusted for market differentials, were used to calculate the ceiling test. Accordingly, the Company was required to write down its oil and natural gas producing properties. The Company recorded a $500.4 million ($315.3 million after tax) noncash write-down in operating expenses from discontinued operations in the first quarter of 2015.

Fidelity previously held commodity derivatives that were not designated as hedging instruments. The amount of gain (loss) recognized in discontinued operations, before tax, was $(18.3) million and $23.4 million in the years ended December 31, 2015 and 2014, respectively.

On February 10, 2014, the Company entered into agreements to purchase working interests and leasehold positions in oil and natural gas production assets in the southern Powder River Basin of Wyoming. The effective date of the acquisition was October 1, 2013, and the closing occurred on March 6, 2014. The total purchase price, including purchase price adjustments, for acquisitions in 2014 was approximately $209.2 million , including the above acquisition which is reflected in discontinued operations. Pro forma financial amounts reflecting the effects of the acquisitions are not presented, as such acquisitions were not material to the Company's financial position or results of operations.

CEM In 2007, Centennial Resources sold CEM to Bicent. In connection with the sale, Centennial Resources agreed to indemnify Bicent and its affiliates from certain third party claims arising out of or in connection with Centennial Resources' ownership or operation of CEM prior to the sale. In addition, Centennial had previously guaranteed CEM's obligations under a construction contract. The Company incurred legal expenses and had a benefit related to the resolution of this matter in the second quarter of 2014, which are reflected in discontinued operations in the consolidated financial statements and accompanying notes.

Dakota Prairie Refining, Fidelity and CEM The reconciliation of the major classes of income and expense constituting pretax income (loss) from discontinued operations, which includes Dakota Prairie Refining, Fidelity and CEM, to the after-tax net income (loss) from discontinued operations on the Company's Consolidated Statements of Income at December 31 were as follows:

	2016	2015	2014
		(In thousands)	
Operating revenues	**$ 123,024**	$ 363,115	$ 547,571
Operating expenses	**513,813**	1,666,941	386,651
Operating income (loss)	**(390,789)**	(1,303,826)	160,920
Other income	**306**	3,149	1,898
Interest expense	**1,753**	2,124	145
Income (loss) from discontinued operations before income taxes	**(392,236)**	(1,302,801)	162,673
Income taxes	**(91,882)**	(468,721)	53,362
Income (loss) from discontinued operations	**(300,354)**	(834,080)	109,311
Loss from discontinued operations attributable to noncontrolling interest	**(131,691)**	(35,256)	(3,895)
Income (loss) from discontinued operations attributable to the Company	**$ (168,663)**	$ (798,824)	$ 113,206

The pretax loss from discontinued operations attributable to the Company, related to the operations of and activity associated with Dakota Prairie Refining, was $253.5 million , $31.5 million and $3.2 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Note 3 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2016 , were as follows:

	Balance at January 1, 2016 *	Goodwill Acquired During the Year	Held for Sale	Balance at December 31, 2016
		(In thousands)		
Natural gas distribution	$ 345,736	$ —	$ —	$ 345,736
Pipeline and midstream	9,737	—	(9,737)	—
Construction materials and contracting	176,290	—	—	176,290
Construction services	103,441	6,324	—	109,765
Total	$ 635,204	$ 6,324	$ (9,737)	$ 631,791

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and midstream segment, which occurred in prior periods.

The changes in the carrying amount of goodwill for the year ended December 31, 2015 , were as follows:

	Balance at January 1, 2015 *	Goodwill Acquired During the Year	Balance at December 31, 2015 *
		(In thousands)	
Natural gas distribution	$ 345,736	$ —	$ 345,736
Pipeline and midstream	9,737	—	9,737
Construction materials and contracting	176,290	—	176,290
Construction services	103,441	—	103,441
Total	$ 635,204	$ —	$ 635,204

* Balance is presented net of accumulated impairment of $12.3 million at the pipeline and midstream segment, which occurred in prior periods.

Other amortizable intangible assets at December 31 were as follows:

	2016	2015
	(In thousands)	
Customer relationships	$ 17,145	$ 20,975
Less accumulated amortization	13,917	16,845
	3,228	4,130
Noncompete agreements	2,430	4,409
Less accumulated amortization	1,658	3,655
	772	754
Other	7,768	8,304
Less accumulated amortization	5,843	5,846
	1,925	2,458
Total	$ 5,925	$ 7,342

Amortization expense for amortizable intangible assets for the years ended December 31, 2016 , 2015 and 2014 , was $2.5 million , $2.5 million and $3.2 million , respectively. Estimated amortization expense for intangible assets is $2.2 million in 2017 , $1.2 million in 2018 , $1.0 million in 2019 , $500,000 in 2020 , $200,000 in 2021 and $800,000 thereafter.

Note 4 - Regulatory Assets and Liabilities

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

	Estimated Recovery Period *	2016	2015
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	$ 176,025	$ 185,832
Taxes recoverable from customers (a)	Over plant lives	28,278	27,682
Manufactured gas plant sites remediation (a)	—	18,259	18,617
Asset retirement obligations (a)	—	42,580	8,000
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	2,242	547
Long-term debt refinancing costs (a)	Up to 21 years	6,248	7,031
Costs related to identifying generation development (a)	Up to 10 years	3,407	3,808
Other (a) (b)	Largely within 1- 4 years	30,281	11,741
Total regulatory assets		307,320	263,258
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		176,972	182,981
Taxes refundable to customers (c)		11,010	17,060
Pension and postretirement benefits (c)		9,099	4,764
Natural gas costs refundable through rate adjustments (d)		25,580	20,884
Other (c) (d)		19,191	17,429
Total regulatory liabilities		241,852	243,118
Net regulatory position		$ 65,468	$ 20,140

* Estimated recovery period for regulatory assets currently being recovered in rates charged to customers.
(a) Included in deferred charges and other assets - other on the Consolidated Balance Sheets.
(b) Included in prepayments and other current assets on the Consolidated Balance Sheets.
(c) Included in deferred credits and other liabilities - other on the Consolidated Balance Sheets.
(d) Included in other accrued liabilities on the Consolidated Balance Sheets.
(e) Recovered as expense is incurred or cash contributions are made.

The regulatory assets are expected to be recovered in rates charged to customers. A portion of the Company's regulatory assets are not earning a return; however, these regulatory assets are expected to be recovered from customers in future rates. As of December 31, 2016 and 2015 , approximately $255.4 million and $224.7 million , respectively, of regulatory assets were not earning a rate of return.

If, for any reason, the Company's regulated businesses cease to meet the criteria for application of regulatory accounting for all or part of their operations, the regulatory assets and liabilities relating to those portions ceasing to meet such criteria would be removed from the

balance sheet and included in the statement of income or accumulated other comprehensive income (loss) in the period in which the discontinuance of regulatory accounting occurs.

Note 5 - Fair Value Measurements

The Company measures its investments in certain fixed-income and equity securities at fair value with changes in fair value recognized in income. The Company anticipates using these investments, which consist of an insurance contract, to satisfy its obligations under its unfunded, nonqualified benefit plans for executive officers and certain key management employees, and invests in these fixed-income and equity securities for the purpose of earning investment returns and capital appreciation. These investments, which totaled $70.9 million and $67.5 million at December 31, 2016 and 2015 , respectively, are classified as investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2016 , 2015 and 2014 , were $3.4 million , $1.7 million and $3.4 million , respectively. The change in fair value, which is considered part of the cost of the plan, is classified in operation and maintenance expense on the Consolidated Statements of Income.

The Company did not elect the fair value option, which records gains and losses in income, for its available-for-sale securities, which include mortgage-backed securities and U.S. Treasury securities. These available-for-sale securities are recorded at fair value and are classified as investments on the Consolidated Balance Sheets. Unrealized gains or losses are recorded in accumulated other comprehensive income (loss). Details of available-for-sale securities were as follows:

December 31, 2016	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 10,546	$ 8	$ (105)	$ 10,449
Total	$ 10,546	$ 8	$ (105)	$ 10,449

December 31, 2015	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 9,128	$ 19	$ (49)	$ 9,098
U.S. Treasury securities	1,315	—	(6)	1,309
Total	$ 10,443	$ 19	$ (55)	$ 10,407

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

The estimated fair values of the Company's assets and liabilities measured on a recurring basis are determined using the market approach.

The Company's Level 2 money market funds are valued at the net asset value of shares held at the end of the period, based on published market quotations on active markets, or using other known sources including pricing from outside sources.

The estimated fair value of the Company's Level 2 mortgage-backed securities and U.S. Treasury securities are based on comparable market transactions, other observable inputs or other sources, including pricing from outside sources.

The estimated fair value of the Company's Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2016 and 2015 , there were no transfers between Levels 1 and 2.

The Company's assets and liabilities measured at fair value on a recurring basis were as follows:

	Fair Value Measurements at December 31, 2016, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2016
	(In thousands)			
Assets:				
Money market funds	$ —	$ 1,602	$ —	$ 1,602
Insurance contract*	—	70,921	—	70,921
Available-for-sale securities:				
Mortgage-backed securities	—	10,449	—	10,449
Total assets measured at fair value	$ —	$ 82,972	$ —	$ 82,972

* The insurance contract invests approximately 52 percent in fixed-income investments, 22 percent in common stock of large-cap companies, 13 percent in common stock of mid-cap companies, 10 percent in common stock of small-cap companies, 1 percent in target date investments and 2 percent in cash equivalents.

	Fair Value Measurements at December 31, 2015, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2015
	(In thousands)			
Assets:				
Money market funds	$ —	$ 1,420	$ —	$ 1,420
Insurance contract*	—	67,459	—	67,459
Available-for-sale securities:				
Mortgage-backed securities	—	9,098	—	9,098
U.S. Treasury securities	—	1,309	—	1,309
Total assets measured at fair value	$ —	$ 79,286	$ —	$ 79,286

* The insurance contract invests approximately 63 percent in fixed-income investments, 19 percent in common stock of large-cap companies, 9 percent in common stock of mid-cap companies, 7 percent in common stock of small-cap companies, 1 percent in target date investments and 1 percent in cash equivalents.

The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements, including long-lived asset impairments. These assets are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The Company reviews the carrying value of its long-lived assets, excluding goodwill, whenever events or changes in circumstances indicate that such carrying amounts may not be recoverable.

During the second quarter of 2015, coalbed natural gas gathering assets at the pipeline and midstream segment were reviewed for impairment and found to be impaired and were written down to their estimated fair value using the income approach. Under this approach, fair value is determined by using the present value of future estimated cash flows. The factors used to determine the estimated future cash flows include, but are not limited to, internal estimates of gathering revenue, future commodity prices and operating costs and equipment salvage values. The estimated cash flows are discounted using a rate that approximates the weighted average cost of capital of a market participant. These fair value inputs are not typically observable. At June 30, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $1.1 million .

During the third quarter of 2015, the Company was negotiating the sale of certain non-strategic natural gas gathering assets at the pipeline and midstream segment and as a result these assets were found to be impaired and were written down to their estimated fair value using the market approach. The estimated fair value of natural gas gathering assets that were impaired at September 30, 2015, was largely determined by agreed upon pricing in a purchase and sale agreement that the Company was negotiating, and these assets were sold in the fourth quarter of 2015. At September 30, 2015, natural gas gathering assets were written down to the nonrecurring fair value measurement of $10.8 million .

The fair value of these natural gas gathering assets have been categorized as Level 3 in the fair value hierarchy.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. For more information on these Level 3 nonrecurring fair value measurements, see Note 2 .

The Company's long-term debt is not measured at fair value on the Consolidated Balance Sheets and the fair value is being provided for disclosure purposes only. The fair value was based on discounted future cash flows using current market interest rates. The estimated fair value of the Company's Level 2 long-term debt at December 31 was as follows:

	2016		2015	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 1,790,159**	**$ 1,841,885**	$ 1,796,163	$ 1,819,828

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

Note 6 - Debt

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

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

Company	Facility		Facility Limit		Amount Outstanding at December 31, 2016		Amount Outstanding at December 31, 2015		Letters of Credit at December 31, 2016		Expiration Date
							(In millions)				
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement	(a)	$ 175.0		$ 111.0	(b)	$ 44.5	(b)	$ —		5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement		$ 50.0	(c)	$ —		$ —		$ 2.2	(d)	7/9/18
Intermountain Gas Company	Revolving credit agreement		$ 65.0	(e)	$ 20.9		$ 47.9		$ —		7/13/18
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0		$ 151.0	(b)	$ 18.0	(b)	$ —		9/23/21

(a) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of the Company on stated conditions, up to a maximum of $225.0 million). There were no amounts outstanding under the credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $75.0 million .
(d) Outstanding letter(s) of credit reduce the amount available under the credit agreement.
(e) Certain provisions allow for increased borrowings, up to a maximum of $90.0 million .
(f) The commercial paper program is supported by a revolving credit agreement with various banks (provisions allow for increased borrowings, at the option of Centennial on stated conditions, up to a maximum of $600.0 million). There were no amounts outstanding under the credit agreement.

The Company's and Centennial's respective commercial paper programs are supported by revolving credit agreements. While the amount of commercial paper outstanding does not reduce available capacity under the respective revolving credit agreements, the Company and Centennial do not issue commercial paper in an aggregate amount exceeding the available capacity under their credit agreements. The commercial paper borrowings may vary during the period, largely the result of fluctuations in working capital requirements due to the seasonality of the construction businesses.

The following includes information related to the preceding table.

Long-term debt

MDU Resources Group, Inc. The Company's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

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

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

On November 21, 2016, the Company entered into a $100.0 million note purchase agreement. The Company issued $40.0 million of Senior Notes under the agreement on November 21, 2016, with a due date of November 21, 2046, at an interest rate of 4.15 percent . The Company contracted to issue an additional $60.0 million of Senior Notes under the agreement on March 21, 2017, with due dates ranging from March 2032 to March 2037 at a weighted average interest rate of 3.61 percent .

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

Cascade Natural Gas Corporation Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Cascade not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Cascade's credit agreement also contains cross-default provisions. These provisions state that if Cascade fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, Cascade will be in default under the revolving credit agreement.

Intermountain Gas Company Any borrowings under the revolving credit agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued borrowings.

The credit agreement contains customary covenants and provisions, including a covenant of Intermountain not to permit, at any time, the ratio of total debt to total capitalization to be greater than 65 percent. Other covenants include restrictions on the sale of certain assets, limitations on indebtedness and the making of certain investments.

Intermountain's credit agreement also contains cross-default provisions. These provisions state that if Intermountain fails to make any payment with respect to any indebtedness or contingent obligation, in excess of a specified amount, under any agreement that causes such indebtedness to be due prior to its stated maturity or the contingent obligation to become payable, or certain conditions result in an early termination date under any swap contract that is in excess of a specified amount, then Intermountain will be in default under the revolving credit agreement.

On November 9, 2016, Intermountain issued $30.0 million of Senior Notes with a due date of November 9, 2046, at an interest rate of 4.0 percent.

Centennial Energy Holdings, Inc. On September 23, 2016, Centennial amended its revolving credit agreement to decrease the borrowing limit by $150.0 million to $500.0 million and extend the termination date to September 23, 2021. Centennial's revolving credit agreement supports its commercial paper program. Commercial paper borrowings under this agreement are classified as long-term debt as they are intended to be refinanced on a long-term basis through continued commercial paper borrowings.

Centennial's revolving credit agreement and certain debt outstanding under an expired uncommitted long-term master shelf agreement contain customary covenants and provisions, including a covenant of Centennial, not to permit, as of the end of any fiscal quarter, the ratio of total consolidated debt to total consolidated capitalization to be greater than 65 percent (for the revolving credit agreement) and a covenant of Centennial and certain of its subsidiaries, not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 60 percent (for the master shelf agreement). The master shelf agreement also includes a covenant that does not permit the ratio of Centennial's EBITDA to interest expense, for the 12-month period ended each fiscal quarter, to be less than 1.75 to 1. Other covenants include restricted payments, restrictions on the sale of certain assets, limitations on subsidiary indebtedness, minimum consolidated net worth, limitations on priority debt and the making of certain loans and investments.

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

WBI Energy Transmission, Inc. On May 17, 2016, WBI Energy Transmission entered into an amendment to its amended and restated uncommitted note purchase and private shelf agreement to increase the aggregate issuance capacity from $175.0 million to $200.0 million and extend the issuance period to May 16, 2019. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2016 , which reduced the remaining capacity under this uncommitted private shelf agreement to $100.0 million . This agreement contains customary covenants and provisions, including a covenant of WBI Energy Transmission not to permit, as of the end of any fiscal quarter, the ratio of total debt to total capitalization to be greater than 55 percent. Other covenants include a limitation on priority debt and restrictions on the sale of certain assets and the making of certain investments.

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

	2016	2015
	(In thousands)	
Senior Notes at a weighted average rate of 4.87%, due on dates ranging from August 31, 2017 to January 15, 2055	**$ 1,437,831**	$ 1,616,246
Commercial paper at a weighted average rate of 1.27%, supported by revolving credit agreements	**262,000**	62,500
Medium-Term Notes at a weighted average rate of 6.68%, due on dates ranging from September 1, 2020 to March 16, 2029	**50,000**	50,000
Other notes at a weighted average rate of 5.25%, due on February 1, 2035	**24,471**	24,589
Credit agreements at a weighted average rate of 3.14%, due on dates ranging from July 13, 2018 to November 30, 2038	**21,793**	48,906
Unamortized debt issuance costs	**(5,832)**	(6,069)
Discount	**(104)**	(9)
Total long-term debt	**1,790,159**	1,796,163
Less current maturities	**43,598**	238,539
Net long-term debt	**$ 1,746,561**	$ 1,557,624

Schedule of Debt Maturities Long-term debt maturities for the five years and thereafter following December 31, 2016 , were as follows:

	2017	2018	2019	2020	2021	Thereafter
				(In thousands)		
Long-term debt maturities	$ 43,598	$ 169,449	$ 162,154	$ 15,021	$ 151,013	$ 1,254,860

Note 7 - Asset Retirement Obligations

The Company records obligations related to retirement costs of natural gas distribution mains and lines, natural gas transmission lines, storage facilities, decommissioning of certain electric generating facilities, reclamation of certain aggregate properties, special handling and disposal of hazardous materials at certain electric generating facilities, natural gas distribution facilities and buildings, and certain other obligations as asset retirement obligations.

A reconciliation of the Company's liability, which is included in other accrued liabilities and deferred credits and other liabilities - other on the Consolidated Balance Sheets, for the years ended December 31 was as follows:

		2016		2015
		(In thousands)		
Balance at beginning of year	$	**242,224**	$	27,211
Liabilities incurred		**15,114**		2,751
Liabilities settled		**(4,338)**		(1,708)
Accretion expense		**13,918**		2,134
Revisions in estimates		**48,052**		211,836
Balance at end of year	$	**314,970**	$	242,224

The 2016 revisions in estimates consist principally of updated asset retirement obligation costs associated with natural gas transmission lines and storage facilities at the pipeline and midstream segment. The 2015 revisions in estimates consist principally of updated asset retirement obligation costs associated with natural gas distribution mains and lines at the natural gas distribution segment.

The Company believes that largely all expenses related to asset retirement obligations at the Company's regulated operations will be recovered in rates over time and, accordingly, defers such expenses as regulatory assets. For more information on the Company's regulatory assets and liabilities, see Note 4 .

Note 8 - Preferred Stocks

Preferred stocks at December 31 were as follows:

		2016		2015
		(In thousands, except shares and per share amounts)		
Authorized:				
Preferred -				
500,000 shares, cumulative, par value $100, issuable in series				
Preferred stock A -				
1,000,000 shares, cumulative, without par value, issuable in series (none outstanding)				
Preference -				
500,000 shares, cumulative, without par value, issuable in series (none outstanding)				
Outstanding:				
4.50% Series - 100,000 shares	$	**10,000**	$	10,000
4.70% Series - 50,000 shares		**5,000**		5,000
Total preferred stocks	$	**15,000**	$	15,000

For the years 2016 , 2015 and 2014 , dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. The 4.50% Series and 4.70% Series preferred stocks outstanding are subject to redemption, in whole or in part, at the option of the Company with certain limitations on 30 days notice on any quarterly dividend date at a redemption price, plus accrued dividends, of $105 per share and $102 per share, respectively.

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

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

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

Note 9 - Common Stock

For the years 2016 , 2015 and 2014 , dividends declared on common stock were $.7550 , $.7350 and $.7150 per common share, respectively.

The Stock Purchase Plan provided interested investors the opportunity to make optional cash investments and to reinvest all or a percentage of their cash dividends in shares of the Company's common stock. The K-Plan provides participants the option to invest in the Company's common stock. From January 2014 through August 2015, the Stock Purchase Plan and K-Plan, with respect to Company stock, purchased shares of authorized but unissued common stock from the Company. From September 2015 through December 2016, the K-Plan purchased shares of common stock on the open market. At December 31, 2016 , there were 7.8 million shares of common stock reserved for original issuance under the K-Plan. From September 2015 through December 4, 2016, the Stock Purchase Plan purchased shares of common stock on the open market. On December 5, 2016, the Stock Purchase Plan was terminated and all remaining shares reserved for original issuance under the plan have been de-registered.

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

Pursuant to a covenant under a credit agreement, Centennial may only declare or pay distributions if as of the last day of any fiscal quarter, the ratio of Centennial's average consolidated indebtedness as of the last day of such fiscal quarter and each of the preceding three fiscal quarters to Centennial's Consolidated EBITDA does not exceed 3 to 1; and after giving effect to such distribution, all distributions made during the 12-month period ending on the last day of the fiscal quarter in which such distribution is made will not exceed the remainder of Centennial's Consolidated EBITDA minus Centennial's capital expenditures less the net cash proceeds from all sales of capital assets from continuing operations, for the immediately preceding 12-month period. Intermountain and Cascade have regulatory limitations on the amount of dividends each can pay. Based on these limitations, approximately $1.3 billion of the net assets of the Company's subsidiaries were restricted from being used to transfer funds to the Company at December 31, 2016 . In addition, the Company's credit agreement also contains restrictions on dividend payments. The most restrictive limitation requires the Company not to permit the ratio of funded debt to capitalization (determined with respect to the Company alone, excluding its subsidiaries) to be greater than 65 percent. Based on this limitation, approximately $351 million of the Company's (excluding its subsidiaries) net assets, which represents common stockholders' equity including retained earnings, would be restricted from use for dividend payments at December 31, 2016 . In addition, state regulatory commissions may require the Company to maintain certain capitalization ratios. These requirements are not expected to affect the Company's ability to pay dividends in the near term.

Note 10 - Stock-Based Compensation

The Company has several stock-based compensation plans under which it is currently authorized to grant restricted stock and stock. As of December 31, 2016 , there are 5.5 million remaining shares available to grant under these plans. The Company generally issues new shares of common stock to satisfy employee performance share awards and purchases shares on the open market for nonemployee director stock awards.

Total stock-based compensation expense (after tax) was $3.3 million , $2.9 million and $4.4 million in 2016 , 2015 and 2014 , respectively.

As of December 31, 2016 , total remaining unrecognized compensation expense related to stock-based compensation was approximately $4.9 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock awards

Nonemployee directors may receive shares of common stock instead of cash in payment for directors' fees under the nonemployee director stock compensation plan. There were 37,218 shares with a fair value of $1.1 million , 58,181 shares with a fair value of $1.1 million and 43,088 shares with a fair value of $1.1 million issued under this plan during the years ended December 31, 2016 , 2015 and 2014 , respectively.

Performance share awards

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

Target grants of performance shares outstanding at December 31, 2016 , were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2014	2014-2016	136,901
February 2015	2015-2017	200,112
June 2015	2015-2017	14,441
February 2016	2016-2018	310,583
March 2016	2016-2018	2,151

Participants may earn from zero to 200 percent of the target grant of shares based on the Company's total shareholder return relative to that of the selected peer group. Compensation expense is based on the grant-date fair value as determined by Monte Carlo simulation. The blended volatility term structure ranges are comprised of 50 percent historical volatility and 50 percent implied volatility. Risk-free interest rates were based on U.S. Treasury security rates in effect as of the grant date. Assumptions used for grants of performance shares issued in 2016 , 2015 and 2014 were:

			2016			2015			2014
Weighted average grant-date fair value			**$14.60**			$18.98			$41.13
Blended volatility range	**29.25%**	**–**	**32.51%**	22.86%	–	24.61%	18.94%	–	20.43%
Risk-free interest rate range	**.47%**	**–**	**.92%**	.05%	–	1.07%	.03%	–	.74%
Weighted average discounted dividends per share			**$1.56**			$1.57			$2.15

The fair value of the performance shares that vested during the years ended December 31, 2016 and 2014, was $953,000 and $16.6 million , respectively. There were no performance shares that vested in 2015.

A summary of the status of the performance share awards for the year ended December 31, 2016 , was as follows:

	Number of Shares	Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	565,896	$ 27.90
Granted	324,205	14.60
Less:		
Vested	58,401	29.01
Forfeited	167,512	27.30
Nonvested at end of period	664,188	$ 21.47

Note 11 - Income Taxes

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

	2016	2015	2014
		(In thousands)	
United States	**$ 326,252**	$ 248,379	$ 249,501
Foreign	**(24)**	(1,326)	(52)
Income before income taxes from continuing operations	**$ 326,228**	$ 247,053	$ 249,449

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

	2016	2015	2014
		(In thousands)	
Current:			
Federal	$ 81,989	$ 85,897	$ 8,837
State	13,190	10,093	622
Foreign	2	30	—
	95,181	96,020	9,459
Deferred:			
Income taxes:			
Federal	(2,102)	(19,632)	52,041
State	1,184	(5,304)	1,913
Investment tax credit - net	(1,131)	(420)	1,009
	(2,049)	(25,356)	54,963
Total income tax expense	$ 93,132	$ 70,664	$ 64,422

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

	2016	2015
	(In thousands)	
Deferred tax assets:		
Postretirement	$ 87,872	$ 97,666
Compensation-related	44,995	33,714
Alternative minimum tax credit carryforward	29,338	28,169
Federal renewable energy credit	16,944	3,400
Customer advances	13,524	12,623
Legal and environmental contingencies	9,895	6,377
Asset retirement obligations	8,867	8,694
Other	46,957	43,306
Total deferred tax assets	258,392	233,949
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	774,838	756,444
Postretirement	70,670	71,835
Intangible asset amortization	26,413	23,950
Other	45,580	36,359
Total deferred tax liabilities	917,501	888,588
Valuation allowance	9,117	8,990
Net deferred income tax liability	$ 668,226	$ 663,629

As of December 31, 2016 and 2015 , the Company had various state income tax net operating loss carryforwards of $114.7 million and $116.2 million , respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $43.3 million and $21.3 million , respectively. Included in the state credits are various regulatory investment tax credits of approximately $20.7 million and $13.9 million at December 31, 2016 and 2015, respectively. The federal income tax credit carryforwards expire in 2036 and 2037 if not utilized and state income tax credit carryforwards are due to expire between 2019 and 2042. It is likely that a portion of the benefit from the state carryforwards will not be realized; therefore, valuation allowances have been provided. Changes in tax regulations or assumptions regarding current and future taxable income could require additional valuation allowances in the future. The alternative minimum tax credit carryforwards do not expire. For information regarding net operating loss carryforwards and valuation allowances related to discontinued operations, see Note 2 .

The following table reconciles the change in the net deferred income tax liability from December 31, 2015 , to December 31, 2016 , to deferred income tax expense:

		2016
		(In thousands)
Change in net deferred income tax liability from the preceding table	$	4,597
Deferred taxes associated with other comprehensive income		(825)
Other		(5,821)
Deferred income tax benefit for the period	$	(2,049)

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

Years ended December 31,		2016			2015			2014	
		Amount	%		Amount	%		Amount	%
					(Dollars in thousands)				
Computed tax at federal statutory rate	$	114,179	35.0	$	86,468	35.0	$	87,308	35.0
Increases (reductions) resulting from:									
State income taxes, net of federal income tax		9,027	2.8		8,208	3.3		7,019	2.8
Federal renewable energy credit		(13,544)	(4.2)		(3,400)	(1.4)		(3,655)	(1.5)
Tax compliance and uncertain tax positions		(3,028)	(.9)		(2,607)	(1.0)		(8,568)	(3.4)
Domestic production activities		(6,251)	(1.9)		(6,842)	(2.8)		(3,993)	(1.6)
Other		(7,251)	(2.3)		(11,163)	(4.5)		(13,689)	(5.5)
Total income tax expense	$	93,132	28.5	$	70,664	28.6	$	64,422	25.8

Deferred income taxes have been accrued with respect to temporary differences related to the Company's foreign operations. The amount of cumulative undistributed earnings for which there are temporary differences is approximately $2.4 million at December 31, 2016 . The amount of deferred tax liability, net of allowable foreign tax credits, associated with the undistributed earnings at December 31, 2016 , was approximately $889,000 .

The Company and its subsidiaries file income tax returns in the U.S. federal jurisdiction, and various state, local and foreign jurisdictions. The Company is no longer subject to U.S. federal or non-U.S. income tax examinations by tax authorities for years ending prior to 2012. With few exceptions, as of December 31, 2016 , the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2011.

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

		2016		2015		2014
				(In thousands)		
Balance at beginning of year	$	—	$	105	$	7,845
Settlements		—		—		(7,740)
Lapse of statute of limitations		—		(105)		—
Balance at end of year	$	—	$	—	$	105

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2016 , 2015 and 2014 , the Company recognized approximately $(92,000) , $122,000 and $387,000 , respectively, of interest (income) expense in income tax expense. At December 31, 2016 and 2015 , the Company had accrued receivables of approximately $54,000 and interest payable of $94,000 , respectively, for the receipt or payment of interest.

Note 12 - Cash Flow Information

Cash expenditures for interest and income taxes for the years ended December 31 were as follows:

		2016		2015		2014
				(In thousands)		
Interest, net of amount capitalized and AFUDC - borrowed of $914, $9,288 and $10,069 in 2016, 2015 and 2014, respectively	**$**	**87,920**	$	88,775	$	81,195
Income taxes paid, net*	**$**	**105,908**	$	61,405	$	80,090

* Income taxes paid, net of discontinued operations, were $1.3 million , $2.4 million and $69.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

Noncash investing transactions at December 31 were as follows:

		2016		2015		2014
				(In thousands)		
Property, plant and equipment additions in accounts payable	**$**	**22,712**	$	39,754	$	12,791

Note 13 - Business Segment Data

The Company's reportable segments are those that are based on the Company's method of internal reporting, which generally segregates the strategic business units due to differences in products, services and regulation. The internal reporting of these operating segments is defined based on the reporting and review process used by the Company's chief executive officer. The vast majority of the Company's operations are located within the United States.

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

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

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

The construction services segment provides utility construction services specializing in constructing and maintaining electric and communication lines, gas pipelines, fire suppression systems, and external lighting and traffic signalization. This segment also provides utility excavation and inside electrical and mechanical services, and manufactures and distributes transmission line construction equipment and other supplies.

The Other category includes the activities of Centennial Capital, which insures various types of risks as a captive insurer for certain of the Company's subsidiaries. The function of the captive insurer is to fund the deductible layers of the insured companies' general liability, automobile liability and pollution liability coverages. Centennial Capital also owns certain real and personal property. The Other category also includes certain general and administrative costs (reflected in operation and maintenance expense) and interest expense which were previously allocated to the refining business and Fidelity and do not meet the criteria for income (loss) from discontinued operations. The Other category also includes Centennial Resources' former investment in the Brazilian Transmission Lines.

Discontinued operations includes the results of Dakota Prairie Refining and Fidelity other than certain general and administrative costs and interest expense as described above. Dakota Prairie Refining refined crude oil and produced and sold diesel fuel, naphtha, ATBs and other by-products of the production process. In the second quarter of 2016, the Company sold all of the outstanding membership interests in Dakota Prairie Refining. Fidelity engaged in oil and natural gas development and production activities in the Rocky Mountain and Mid-Continent/Gulf States regions of the United States. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. Discontinued operations also includes legal expenses and a benefit related to the vacation of an arbitration award in 2014 related to Centennial Resources. For more information on discontinued operations, see Note 2 .

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

		2016		2015		2014
				(In thousands)		
External operating revenues:						
Regulated operations:						
Electric	**$**	**322,356**	$	280,615	$	277,874
Natural gas distribution		**766,115**		817,419		921,986
Pipeline and midstream		**52,983**		51,004		47,043
		1,141,454		1,149,038		1,246,903
Nonregulated operations:						
Pipeline and midstream		**39,602**		54,281		64,494
Construction materials and contracting		**1,873,696**		1,901,530		1,740,089
Construction services		**1,072,663**		907,767		1,062,055
Other		**1,413**		1,436		1,532
		2,987,374		2,865,014		2,868,170
Total external operating revenues	**$**	**4,128,828**	$	4,014,052	$	4,115,073
Intersegment operating revenues:						
Regulated operations:						
Electric	**$**	**—**	$	—	$	—
Natural gas distribution		**—**		—		—
Pipeline and midstream		**48,794**		49,065		45,013
		48,794		49,065		45,013
Nonregulated operations:						
Pipeline and midstream		**223**		554		742
Construction materials and contracting		**574**		2,752		25,241
Construction services		**609**		18,660		57,474
Other		**7,230**		7,755		7,832
		8,636		29,721		91,289
Intersegment eliminations		**(57,430)**		(78,786)		(136,302)
Total intersegment operating revenues	**$**	**—**	$	—	$	—
Depreciation, depletion and amortization:						
Electric	**$**	**50,220**	$	37,583	$	35,008
Natural gas distribution		**65,426**		64,756		54,700
Pipeline and midstream		**24,885**		27,981		29,749
Construction materials and contracting		**58,413**		65,937		68,557
Construction services		**15,307**		13,420		12,874
Other		**2,067**		2,070		2,196
Total depreciation, depletion and amortization	**$**	**216,318**	$	211,747	$	203,084
Interest expense:						
Electric	**$**	**24,982**	$	17,421	$	15,595
Natural gas distribution		**30,405**		29,471		27,217
Pipeline and midstream		**7,903**		9,895		9,946
Construction materials and contracting		**15,265**		15,183		16,368
Construction services		**4,059**		3,959		4,176
Other		**5,854**		15,853		13,823
Intersegment eliminations		**(620)**		(603)		(254)
Total interest expense	**$**	**87,848**	$	91,179	$	86,871

	2016	2015	2014
		(In thousands)	
Income taxes:			
Electric	**$ 1,449**	$ 11,523	$ 12,442
Natural gas distribution	**9,181**	11,377	11,350
Pipeline and midstream	**12,408**	7,505	12,232
Construction materials and contracting	**60,625**	41,619	18,586
Construction services	**17,748**	16,432	24,753
Other	**(2,028)**	(9,834)	(11,136)
Intersegment eliminations	**(6,251)**	(7,958)	(3,805)
Total income taxes	**$ 93,132**	$ 70,664	$ 64,422
Earnings (loss) on common stock:			
Regulated operations:			
Electric	**$ 42,222**	$ 35,914	$ 36,731
Natural gas distribution	**27,102**	23,607	30,484
Pipeline and midstream	**22,060**	20,680	15,440
	91,384	80,201	82,655
Nonregulated operations:			
Pipeline and midstream	**1,375**	(7,430)	9,226
Construction materials and contracting	**102,687**	89,096	51,510
Construction services	**33,945**	23,762	54,432
Other	**(3,231)**	(14,941)	(7,386)
	134,776	90,487	107,782
Intersegment eliminations (a)	**6,251**	5,016	(6,095)
Earnings on common stock before income (loss) from discontinued operations	**232,411**	175,704	184,342
Income (loss) from discontinued operations, net of tax (a)	**(300,354)**	(834,080)	109,311
Loss from discontinued operations attributable to noncontrolling interest	**(131,691)**	(35,256)	(3,895)
Total earnings (loss) on common stock	**$ 63,748**	$ (623,120)	$ 297,548
Capital expenditures:			
Electric	**$ 111,134**	$ 332,876	$ 185,121
Natural gas distribution	**126,272**	130,793	120,613
Pipeline and midstream	**34,467**	18,315	61,754
Construction materials and contracting	**37,845**	48,126	37,896
Construction services	**60,344**	38,269	26,942
Other	**2,358**	3,755	2,131
Total capital expenditures (b)	**$ 372,420**	$ 572,134	$ 434,457
Assets:			
Electric (c)	**$ 1,406,694**	$ 1,325,858	$ 1,028,001
Natural gas distribution (c)	**2,099,296**	2,038,433	1,935,271
Pipeline and midstream	**550,615**	591,651	651,925
Construction materials and contracting	**1,220,459**	1,261,963	1,260,534
Construction services	**513,093**	442,845	437,322
Other (d)	**283,255**	287,940	315,495
Assets held for sale	**211,055**	616,464	2,176,857
Total assets	**$ 6,284,467**	$ 6,565,154	$ 7,805,405

	2016	2015	2014
		(In thousands)	
Property, plant and equipment:			
Electric (c)	**$ 1,888,613**	$ 1,786,148	$ 1,457,101
Natural gas distribution (c)	**2,179,413**	2,076,581	1,904,759
Pipeline and midstream	**672,199**	758,729	818,388
Construction materials and contracting	**1,549,375**	1,553,428	1,529,942
Construction services	**171,361**	163,279	144,395
Other	**49,268**	49,537	50,937
Less accumulated depreciation, depletion and amortization	**2,578,902**	2,489,322	2,385,202
Net property, plant and equipment	**$ 3,931,327**	$ 3,898,380	$ 3,520,320

(a) Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.
(b) Capital expenditures for 2016, 2015 and 2014 include noncash capital expenditure-related accounts payable and AFUDC, totaling $(15.8) million , $35.3 million and $5.1 million , respectively.
(c) Includes allocations of common utility property.
(d) Includes assets not directly assignable to a business (i.e. cash and cash equivalents, certain accounts receivable, certain investments and other miscellaneous current and deferred assets).

Note 14 - Employee Benefit Plans

Pension and other postretirement benefit plans

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

Prior to 2013, defined pension plan benefits and accruals for all nonunion and certain union plans were frozen. On June 30, 2015, an additional union plan was frozen. As of June 30, 2015, all of the Company's defined pension plans were frozen. These employees were eligible to receive additional defined contribution plan benefits.

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

In 2012, the Company modified health care coverage for certain retirees. Effective January 1, 2013, post-65 coverage was replaced by a fixed-dollar subsidy for retirees and spouses to be used to purchase individual insurance through an exchange.

Changes in benefit obligation and plan assets for the years ended December 31, 2016 and 2015 , and amounts recognized in the Consolidated Balance Sheets at December 31, 2016 and 2015 , were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	**2016**	2015
		(In thousands)		
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 442,960**	$ 475,337	**$ 92,734**	$ 99,012
Service cost	**—**	86	**1,647**	1,816
Interest cost	**17,218**	17,141	**3,688**	3,607
Plan participants' contributions	**—**	—	**1,405**	1,408
Actuarial (gain) loss	**1,882**	(24,875)	**(3,872)**	(5,873)
Benefits paid	**(25,753)**	(24,729)	**(6,298)**	(7,236)
Benefit obligation at end of year	**436,307**	442,960	**89,304**	92,734
Change in net plan assets:				
Fair value of plan assets at beginning of year	**332,667**	354,363	**82,593**	87,586
Actual gain (loss) on plan assets	**26,595**	(10,879)	**4,184**	258
Employer contribution	**—**	13,912	**962**	577
Plan participants' contributions	**—**	—	**1,405**	1,408
Benefits paid	**(25,753)**	(24,729)	**(6,298)**	(7,236)
Fair value of net plan assets at end of year	**333,509**	332,667	**82,846**	82,593
Funded status - under	**$ (102,798)**	$ (110,293)	**$ (6,458)**	$ (10,141)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Other assets (noncurrent)	**$ —**	$ —	**$ 13,131**	$ 5,095
Other accrued liabilities (current)	**—**	—	**(538)**	(421)
Other liabilities (noncurrent)	**(102,798)**	(110,293)	**(19,051)**	(14,815)
Net amount recognized	**$ (102,798)**	$ (110,293)	**$ (6,458)**	$ (10,141)
Amounts recognized in accumulated other comprehensive (income) loss consist of:				
Actuarial loss	**$ 198,668**	$ 208,671	**$ 17,470**	$ 22,484
Prior service cost (credit)	**—**	—	**(13,003)**	(14,374)
Total	**$ 198,668**	$ 208,671	**$ 4,467**	$ 8,110

Employer contributions and benefits paid in the preceding table include only those amounts contributed directly to, or paid directly from, plan assets. Accumulated other comprehensive (income) loss in the above table includes amounts related to regulated operations, which are recorded as regulatory assets (liabilities) and are expected to be reflected in rates charged to customers over time. For more information on regulatory assets (liabilities), see Note 4 .

Unrecognized pension actuarial losses in excess of 10 percent of the greater of the projected benefit obligation or the market-related value of assets are amortized over the average life expectancy of plan participants for frozen plans. The market-related value of assets is determined using a five-year average of assets.

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

	2016	2015
	(In thousands)	
Projected benefit obligation	**$ 436,307**	$ 442,960
Accumulated benefit obligation	**$ 436,307**	$ 442,960
Fair value of plan assets	**$ 333,509**	$ 332,667

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

	Pension Benefits			Other Postretirement Benefits		
	2016	2015	2014	**2016**	2015	2014
			(In thousands)			
Components of net periodic benefit cost (credit):						
Service cost	**$ —**	$ 86	$ 129	**$ 1,647**	$ 1,816	$ 1,518
Interest cost	**17,218**	17,141	17,682	**3,688**	3,607	3,521
Expected return on assets	**(20,924)**	(22,254)	(21,218)	**(4,533)**	(4,795)	(4,617)
Amortization of prior service cost (credit)	**—**	36	71	**(1,371)**	(1,371)	(1,393)
Recognized net actuarial loss	**6,215**	7,016	4,869	**1,491**	1,960	649
Curtailment loss	**—**	258	—	**—**	—	—
Net periodic benefit cost (credit), including amount capitalized	**2,509**	2,283	1,533	**922**	1,217	(322)
Less amount capitalized	**381**	316	388	**(52)**	120	(21)
Net periodic benefit cost (credit)	**2,128**	1,967	1,145	**974**	1,097	(301)
Other changes in plan assets and benefit obligations recognized in accumulated other comprehensive (income) loss:						
Net (gain) loss	**(3,789)**	8,257	77,238	**(3,523)**	(1,336)	15,114
Amortization of actuarial loss	**(6,215)**	(7,016)	(4,869)	**(1,491)**	(1,960)	(649)
Amortization of prior service (cost) credit	**—**	(294)	(71)	**1,371**	1,371	1,393
Total recognized in accumulated other comprehensive (income) loss	**(10,004)**	947	72,298	**(3,643)**	(1,925)	15,858
Total recognized in net periodic benefit cost (credit) and accumulated other comprehensive (income) loss	**$ (7,876)**	$ 2,914	$ 73,443	**$ (2,669)**	$ (828)	$ 15,557

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 is $6.4 million . The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss into net periodic benefit cost in 2017 are $900,000 and $1.4 million , respectively. Prior service cost is amortized on a straight line basis over the average remaining service period of active participants.

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

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	**2016**	2015
Discount rate	**3.83%**	4.00%	**3.86%**	4.06%
Expected return on plan assets	**6.75%**	6.75%	**5.75%**	5.75%
Rate of compensation increase	**N/A**	N/A	**3.00%**	3.00%

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

	Pension Benefits		Other Postretirement Benefits	
	2016	2015	**2016**	2015
Discount rate	**4.00%**	3.70%	**4.06%**	3.74%
Expected return on plan assets	**6.75%**	7.00%	**5.75%**	6.00%
Rate of compensation increase	**N/A**	N/A	**3.00%**	3.00%

The expected rate of return on pension plan assets is based on a targeted asset allocation range determined by the funded ratio of the plan. As of December 31, 2016, the expected rate of return on pension plan assets is based on the targeted asset allocation range of 40 percent to 50 percent equity securities and 50 percent to 60 percent fixed-income securities and the expected rate of return from these asset categories. The expected rate of return on other postretirement plan assets is based on the targeted asset allocation range of 30 percent to 40 percent equity securities and 60 percent to 70 percent fixed-income securities and the expected rate of return from these asset categories. The expected return on plan assets for other postretirement benefits reflects insurance-related investment costs.

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

	2016	2015
Health care trend rate assumed for next year	**8.6% – 10.7%**	4.0% – 8.0%
Health care cost trend rate - ultimate	**4.5%**	5.0% – 6.0%
Year in which ultimate trend rate achieved	**2024**	2021

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

Assumed health care cost trend rates may have a significant effect on the amounts reported for the health care plans. A one percentage point change in the assumed health care cost trend rates would have had the following effects at December 31, 2016 :

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 255	$ (210)
Effect on postretirement benefit obligation	$ 5,741	$ (4,834)

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

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

The estimated fair values of the Company's pension plans' assets are determined using the market approach.

The carrying value of the pension plans' Level 2 cash equivalents approximates fair value and is determined using observable inputs in active markets or the net asset value of shares held at year end, which is determined using other observable inputs including pricing from outside sources.

The estimated fair value of the pension plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the pension plans' Level 1 and Level 2 collective and mutual funds are based on the net asset value of shares held at year end, based on either published market quotations on active markets or other known sources including pricing from outside sources.

The estimated fair value of the pension plans' Level 2 corporate and municipal bonds is determined using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, future cash flows and other reference data.

The estimated fair value of the pension plans' Level 1 U.S. Government securities are valued based on quoted prices on an active market.

The estimated fair value of the pension plans' Level 2 U.S. Government securities are valued mainly using other observable inputs, including benchmark yields, reported trades, broker/dealer quotes, bids, offers, to be announced prices, future cash flows and other reference data. Some of these securities are valued using pricing from outside sources.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2016 and 2015 , there were no transfers between Levels 1 and 2.

The fair value of the Company's pension plans' assets (excluding cash) by class were as follows:

	Fair Value Measurements at December 31, 2016, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2016
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 6,347	$ —	$ 6,347
Equity securities:				
U.S. companies	11,348	—	—	11,348
International companies	1,584	—	—	1,584
Collective and mutual funds*	162,055	64,052	—	226,107
Corporate bonds	—	68,677	—	68,677
Municipal bonds	—	11,002	—	11,002
U.S. Government securities	4,352	2,044	—	6,396
Total assets measured at fair value	$ 179,339	$ 152,122	$ —	$ 331,461

* Collective and mutual funds invest approximately 29 percent in common stock of international companies, 21 percent in corporate bonds, 20 percent in common stock of large-cap U.S. companies, 8 percent in cash equivalents, 7 percent in U.S. Government securities and 15 percent in other investments.

	Fair Value Measurements at December 31, 2015, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2015
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 8,379	$ —	$ 8,379
Equity securities:				
U.S. companies	15,135	—	—	15,135
International companies	2,332	—	—	2,332
Collective and mutual funds*	154,400	63,568	—	217,968
Corporate bonds	—	62,145	—	62,145
Municipal bonds	—	11,680	—	11,680
U.S. Government securities	5,288	6,823	—	12,111
Total assets measured at fair value	$ 177,155	$ 152,595	$ —	$ 329,750

* Collective and mutual funds invest approximately 29 percent in common stock of international companies, 19 percent in common stock of large-cap U.S. companies, 16 percent in corporate bonds, 16 percent in cash equivalents, 6 percent in common stock of mid-cap U.S. companies and 14 percent in other investments.

The estimated fair values of the Company's other postretirement benefit plans' assets are determined using the market approach.

The estimated fair value of the other postretirement benefit plans' Level 2 cash equivalents is valued at the net asset value of shares held at year end, based on published market quotations on active markets, or using other known sources including pricing from outside sources.

The estimated fair value of the other postretirement benefit plans' Level 1 equity securities is based on the closing price reported on the active market on which the individual securities are traded.

The estimated fair value of the other postretirement benefit plans' Level 2 insurance contract is based on contractual cash surrender values that are determined primarily by investments in managed separate accounts of the insurer. These amounts approximate fair value. The managed separate accounts are valued based on other observable inputs or corroborated market data.

Though the Company believes the methods used to estimate fair value are consistent with those used by other market participants, the use of other methods or assumptions could result in a different estimate of fair value. For the years ended December 31, 2016 and 2015 , there were no transfers between Levels 1 and 2.

The fair value of the Company's other postretirement benefit plans' assets (excluding cash) by asset class were as follows:

	Fair Value Measurements at December 31, 2016, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2016
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 250	$ —	$ 250
Equity securities:				
U.S. companies	2,328	—	—	2,328
International companies	5	—	—	5
Insurance contract*	—	80,263	—	80,263
Total assets measured at fair value	$ 2,333	$ 80,513	$ —	$ 82,846

* The insurance contract invests approximately 38 percent in corporate bonds, 25 percent in common stock of large-cap U.S. companies, 20 percent in U.S. Government securities, 9 percent in mortgage-backed securities and 8 percent in other investments.

	Fair Value Measurements at December 31, 2015, Using			
	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance at December 31, 2015
		(In thousands)		
Assets:				
Cash equivalents	$ —	$ 3,261	$ —	$ 3,261
Equity securities:				
U.S. companies	2,274	—	—	2,274
International companies	9	—	—	9
Insurance contract*	—	77,044	—	77,044
Total assets measured at fair value	$ 2,283	$ 80,305	$ —	$ 82,588

* The insurance contract invests approximately 36 percent in corporate bonds, 22 percent in U.S. Government securities, 19 percent in common stock of large-cap U.S. companies, 10 percent in mortgage-backed securities and 13 percent in other investments.

The Company expects to contribute approximately $2.0 million to its defined benefit pension plans and approximately $900,000 to its postretirement benefit plans in 2017 .

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

Years	Pension Benefits	Other Postretirement Benefits	Expected Medicare Part D Subsidy
		(In thousands)	
2017	$ 24,798	$ 5,410	$ 168
2018	25,054	5,573	165
2019	25,271	5,603	160
2020	25,616	5,500	154
2021	25,987	5,511	146
2022 - 2026	132,224	27,956	568

Nonqualified benefit plans

In addition to the qualified plan defined pension benefits reflected in the table at the beginning of this note, the Company also has unfunded, nonqualified benefit plans for executive officers and certain key management employees that generally provide for defined benefit payments at age 65 following the employee's retirement or, upon death, to their beneficiaries for a 15-year period. In February 2016, the Company froze the unfunded, nonqualified defined benefit plans to new participants and eliminated benefit increases. Vesting for participants not fully vested was retained. The Company's net periodic benefit cost for these plans was $1.8 million , $7.1 million and $6.6 million in 2016 , 2015 and 2014 , respectively, which reflects a curtailment gain of $3.3 million in the first quarter of 2016 . The total projected benefit obligation for these plans was $101.8 million and $110.8 million at December 31, 2016 and 2015 , respectively. The accumulated benefit obligation for these plans was $101.8 million and $104.6 million at December 31, 2016 and 2015 , respectively. A weighted average discount rate of 3.56 percent and 3.77 percent at December 31, 2016 and 2015 , respectively, and a rate of compensation increase of 4.00 percent at December 31, 2015 , were used to determine benefit obligations. No rate of compensation increase was used to determine the benefit obligation at December 31, 2016 , due to the plans being froze. A discount rate of 3.77 percent and 3.51 percent for the years ended December 31, 2016 and 2015 , respectively, and a rate of compensation increase of 4.00 percent and 4.00 percent for the years ended December 31, 2016 and 2015 , respectively, were used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $6.7 million in 2017 ; $7.1 million in 2018 ; $7.3 million in 2019 ; $7.7 million in 2020 ; $7.7 million in 2021 and $36.4 million for the years 2022 through 2026.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2016 , 2015 and 2014 were $395,000 , $207,000 and $104,000 , respectively.

The Company had investments of $111.0 million and $105.2 million at December 31, 2016 and 2015 , respectively, consisting of equity securities of $62.5 million and $54.2 million , respectively, life insurance carried on plan participants (payable upon the employee's death) of $35.5 million and $34.3 million , respectively, and other investments of $13.0 million and $16.7 million , respectively. The Company anticipates using these investments to satisfy obligations under these plans.

Defined contribution plans

The Company sponsors various defined contribution plans for eligible employees and the costs incurred under these plans were $40.9 million in 2016 , $36.8 million in 2015 and $34.4 million in 2014 .

Multiemployer plans

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

- Assets contributed to the MEPP by one employer may be used to provide benefits to employees of other participating employers
- If a participating employer stops contributing to the plan, the unfunded obligations of the plan may be borne by the remaining participating employers
- If the Company chooses to stop participating in some of its MEPPs, the Company may be required to pay those plans an amount based on the underfunded status of the plan, referred to as a withdrawal liability

The Company's participation in these plans is outlined in the following table. Unless otherwise noted, the most recent Pension Protection Act zone status available in 2016 and 2015 is for the plan's year-end at December 31, 2015 , and December 31, 2014 , respectively. The zone status is based on information that the Company received from the plan and is certified by the plan's actuary. Among other factors, plans in the red zone are generally less than 65 percent funded, plans in the yellow zone are between 65 percent and 80 percent funded, and plans in the green zone are at least 80 percent funded.

Pension Fund	EIN/Pension Plan Number	Pension Protection Act Zone Status 2016	Pension Protection Act Zone Status 2015	FIP/RP Status Pending/Implemented	Contributions 2016	Contributions 2015	Contributions 2014	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Alaska Laborers-Employers Retirement Fund	91-6028298-001	Yellow as of 6/30/2016	Yellow as of 6/30/2015	Implemented	**$ 766**	$ 917	$ 666	No	12/31/2016
Edison Pension Plan	93-6061681-001	Green as of 12/31/2016	Green as of 12/31/2015	No	**6,242**	5,517	9,061	No	12/31/2017
IBEW Local No. 82 Pension Plan	31-6127268-001	Green as of 6/30/2016	Red as of 6/30/2015	Implemented	**2,560**	2,252	1,392	No	12/1/2019
IBEW Local No. 357 Pension Plan A	88-6023284-001	Green	Green	No	**3,016**	1,896	3,575	No	5/31/2018
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/29/2016	Red as of 2/28/2015	Implemented	**773**	745	1,110	No	9/2/2018
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2016	Green as of 5/31/2015	No	**1,221**	1,169	1,125	No	9/30/2019
Local Union 212 IBEW Pension Trust Fund	31-6127280-001	Yellow as of 4/30/2016	Yellow as of 4/30/2015	Implemented	**1,146**	937	568	No	6/2/2019
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red as of 12/31/2016	Red as of 12/31/2015	Implemented	**775**	677	608	No	7/31/2018-3/31/2021
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**6,366**	5,271	6,476	No	1/1/2017-5/31/2020
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming**	83-6011320-001	Red as of 12/31/2016	Red as of 12/31/2015	Implemented	**—**	—	68	No	10/31/2005*
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Red as of 12/31/2016	Red as of 12/31/2015	Implemented	**1,087**	714	676	No	6/30/2017
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	**50**	26	31	No	1/31/2019
Other funds					**20,525**	18,991	17,461		
Total contributions					**$ 44,527**	$ 39,112	$ 42,817		

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

** The Company withdrew from the plan as of October 26, 2014, as discussed later.

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

Pension Fund	Year Contributions to Plan Exceeded More Than 5 Percent of Total Contributions (as of December 31 of the Plan's Year-End)
Edison Pension Plan	2015 and 2014
IBEW Local No. 82 Pension Plan	2015 and 2014
Local Union No. 124 IBEW Pension Trust Fund	2015 and 2014
Local Union 212 IBEW Pension Trust Fund	2015 and 2014
IBEW Local Union No. 357 Pension Plan A	2015 and 2014
IBEW Local 573 Pension Plan	2014
IBEW Local 648 Pension Plan	2015 and 2014
Idaho Plumbers and Pipefitters Pension Plan	2015 and 2014
Minnesota Teamsters Construction Division Pension Fund	2015 and 2014
Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming*	2014
Pension and Retirement Plan of Plumbers and Pipefitters Union Local No. 525	2015 and 2014

* The Company withdrew from the plan as of October 26, 2014, as discussed later.

On September 24, 2014, Knife River provided notice to the Operating Engineers Local 800 & WY Contractors Association, Inc. Pension Plan for Wyoming that it was withdrawing from the plan effective October 26, 2014. In the fourth quarter of 2016, Knife River and the plan entered into a settlement agreement whereby the plan administrator assessed Knife River’s final withdrawal liability with quarterly payments of approximately $42,000 until all benefits are satisfied. Knife River discounted the expected future payments. Based on this calculation, Knife River adjusted its liability accrual from $16.4 million to $5.2 million .

The Company also contributes to a number of multiemployer other postretirement plans under the terms of collective-bargaining agreements that cover its union-represented employees. These plans provide benefits such as health insurance, disability insurance and life insurance to retired union employees. Many of the multiemployer other postretirement plans are combined with active multiemployer health and welfare plans. The Company's total contributions to its multiemployer other postretirement plans, which also includes contributions to active multiemployer health and welfare plans, were $36.1 million , $31.4 million and $34.6 million for the years ended December 31, 2016 , 2015 and 2014 , respectively.

Amounts contributed in 2016 , 2015 and 2014 to defined contribution multiemployer plans were $23.8 million , $19.5 million and $22.0 million , respectively.

Note 15 - Jointly Owned Facilities

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

The Company's share of the stations operating expenses was reflected in the appropriate categories of operating expenses (fuel, operation and maintenance and taxes, other than income) in the Consolidated Statements of Income.

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

		2016		2015
		(In thousands)		
Big Stone Station:				
Utility plant in service	$	**157,144**	$	157,761
Less accumulated depreciation		**49,568**		48,242
	$	**107,576**	$	109,519
Coyote Station:				
Utility plant in service	$	**156,334**	$	140,895
Less accumulated depreciation		**105,928**		94,755
	$	**50,406**	$	46,140
Wygen III:				
Utility plant in service	$	**66,251**	$	65,023
Less accumulated depreciation		**7,550**		6,788
	$	**58,701**	$	58,235

Note 16 - Regulatory Matters

On September 30, 2015, Great Plains filed an application for a natural gas rate increase with the MNPUC. Great Plains requested a total increase of approximately $1.6 million annually or approximately 6.4 percent above current rates to recover increased operating expenses along with increased investment in facilities, including the related depreciation expense and taxes. An interim increase of approximately $1.5 million or approximately 6.4 percent, subject to refund, was effective with service rendered on and after January 1, 2016. The MNPUC issued an order on September 6, 2016, authorizing an increase of approximately $1.1 million annually or approximately 5.2 percent with the requirement that Great Plains submit a compliance filing within 30 days. On September 22, 2016, Great Plains submitted the required compliance filing which included a refund plan to return the amount of interim revenues collected above the final rates. On December 22, 2016, the MNPUC issued an order approving the rates to be implemented January 1, 2017. Great Plains will issue refunds for the difference with interest to customers no later than March 1, 2017.

On October 26, 2015, Montana-Dakota filed an application with the NDPSC requesting a renewable resource cost adjustment rider for the recovery of the Thunder Spirit Wind project. On January 5, 2016, the NDPSC approved the rider to be effective January 7, 2016, resulting in an annual increase on an interim basis, subject to refund, of $15.1 million based upon a 10.5 percent return on equity. The interim rate is pending the determination of the return on equity in the general rate case application filed on October 14, 2016, as discussed in this note.

On October 26, 2015, Montana-Dakota filed an application with the NDPSC for an update to the electric generation resource recovery rider. On March 9, 2016, the NDPSC approved the rider to be effective with service rendered on and after March 15, 2016, which resulted in interim rates, subject to refund, of $9.7 million based upon a 10.5 percent return on equity. The interim rates include recovery of Montana-Dakota's investment in the 88-MW simple-cycle natural gas turbine and associated facilities near Mandan, North Dakota, and the 19 MW of new generation from natural gas-fired internal combustion engines and associated facilities near Sidney, Montana. The net investment authorized for the natural gas-fired internal combustion engines and the return on equity on both investments are pending in the general rate case application filed October 14, 2016, as discussed in this note.

On November 25, 2015, Montana-Dakota filed an application with the NDPSC for an update of its transmission cost adjustment rider for recovery of MISO-related charges and two transmission projects in North Dakota. On February 10, 2016, the NDPSC approved the transmission cost adjustment effective with service rendered on and after February 12, 2016, resulting in an annual increase on an interim basis, subject to refund, of $6.8 million based upon a 10.5 percent return on equity. The interim rate is pending the determination of the return on equity in the general rate case application filed October 14, 2016, as discussed in this note.

On April 29, 2016, Cascade filed an application with the OPUC for a natural gas rate increase of approximately $1.9 million annually or approximately 2.8 percent above current rates. The request includes rate recovery associated with pipeline replacement and improvement projects to ensure the integrity of Cascade's system. On October 6, 2016, Cascade, staff of the OPUC and the interveners in the case filed a stipulation and settlement agreement reflecting an annual increase of approximately $754,000 to be effective March 1, 2017. The OPUC issued an order approving the stipulation and settlement agreement on December 12, 2016.

On June 1, 2016, Cascade filed an application with the WUTC for an annual pipeline replacement cost recovery mechanism of $4.6 million annually or approximately 2.0 percent of additional revenue. The requested increase includes $2.4 million associated with incremental pipeline replacement investments and $2.2 million for an alternative recovery request of incremental operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On October 17, 2016, Cascade filed an update to the application that reduced the incremental pipeline replacement investment to $1.9 million and removed the operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On October 27, 2016, the WUTC allowed the pipeline replacement cost recovery mechanism which was effective November 1, 2016. On June 1, 2016, Cascade filed an accounting order to defer the costs related to the maximum allowable operating pressure validation plan and on November 10, 2016, the WUTC granted the order.

On June 10, 2016, Montana-Dakota filed an application for an increase in electric rates with the WYPSC. Montana-Dakota requested an increase of approximately $3.2 million annually or approximately 13.1 percent above current rates to recover Montana-Dakota's increased investment in facilities along with additional depreciation, operation and maintenance expenses including increased fuel costs, and taxes associated with the increases in investment. On December 28, 2016, Montana-Dakota and the interveners of the case filed a stipulation and agreement reflecting an increase of approximately $2.7 million annually or approximately 11.1 percent above current rates effective for service rendered on and after March 1, 2017. The WYPSC rendered a bench decision approving the stipulation and agreement on January 18, 2017.

On August 12, 2016, Intermountain filed an application with the IPUC for a natural gas rate increase of approximately $10.2 million annually or approximately 4.1 percent above current rates. The request includes rate recovery associated with increased investment in facilities and increased operating expenses. On November 23, 2016, Intermountain provided the IPUC with an updated revenue request of approximately $9.6 million . A hearing has been scheduled for March 1-2, 2017. This matter is pending before the IPUC.

On September 1, 2016, and as amended on January 10, 2017, Montana-Dakota submitted an update to its transmission formula rate under the MISO tariff including a revenue requirement for the Company's multivalue project along with a true-up of prior year expenditures of $11.1 million , which was effective January 1, 2017.

On October 14, 2016, Montana-Dakota filed an application with the NDPSC for an electric rate increase of approximately $13.4 million annually or 6.6 percent above current rates. The request includes rate recovery associated with increased investment in facilities, along with the related depreciation, operation and maintenance expenses and taxes associated with the increased investment. Montana-Dakota requested an interim increase of approximately $ 13.0 million or approximately 6.5 percent, subject to refund, to be effective within 60 days of the filing. On November 21, 2016, Montana-Dakota filed a revised interim increase of approximately $11.7 million , based on adjustments accepted by the NDPSC, or approximately 5.8 percent above current rates, subject to refund. The NDPSC approved the revised interim rates effective with service rendered on or after December 13, 2016. A technical hearing is scheduled for April 10, 2017. This matter is pending before the NDPSC.

On December 2, 2016, Montana-Dakota filed an application with the MTPSC requesting authority to implement gas and electric tax tracking adjustments for Montana state and local taxes and fees that reflect the changes in state and local property taxes applicable to gas and electric utilities pursuant to Montana law. The requested tax tracking adjustments would result in an increase in revenues of approximately $814,000 . On January 17, 2017, the MTPSC issued an order on the tax tracking adjustments. The gas tracking adjustment was approved as an increase to revenues of approximately $474,000 effective January 1, 2017. The electric tax tracking adjustment was approved as an increase to revenues of approximately $251,000 effective May 15, 2017. Montana-Dakota filed a motion for reconsideration of the electric tax tracking adjustment on January 27, 2017. The motion for reconsideration is pending before the MTPSC.

On December 21, 2016, Great Plains filed an application with the MNPUC requesting authority to implement a gas utility infrastructure cost tariff of approximately $456,000 annually effective beginning with service rendered May 20, 2017. The tariff will allow Great Plains to recover infrastructure investments, not previously included in rates, mandated by federal or state agencies associated with Great Plains' pipeline integrity programs. This matter is pending before the MNPUC.

Note 17 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries. The Company accrues a liability for those contingencies when the incurrence of a loss is probable and the amount can be reasonably estimated. If a range of amounts can be reasonably estimated and no amount within the range is a better estimate than any other amount, then the minimum of the range is accrued. The Company does not accrue liabilities when the likelihood that the liability has been incurred is probable but the amount cannot be reasonably estimated or when the liability is believed to be only reasonably possible or remote. For contingencies where an unfavorable outcome is probable or reasonably possible and which are material, the Company discloses the nature of the contingency and, in some circumstances, an estimate of the possible loss. The Company had accrued liabilities of $31.8 million and $19.5 million , which include liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at

December 31, 2016 and 2015 , respectively, including amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note.

Litigation

Natural Gas Gathering Operations Omimex filed a complaint against WBI Energy Midstream in Montana Seventeenth Judicial District Court in July 2010 alleging WBI Energy Midstream breached a gathering contract with Omimex as a result of the increased operating pressures demanded by a third party on a natural gas gathering system in Montana. In December 2011, Omimex filed an amended complaint alleging WBI Energy Midstream breached obligations to operate its gathering system as a common carrier under United States and Montana law. WBI Energy Midstream removed the action to the United States District Court for the District of Montana. The parties subsequently settled the breach of contract claim and, subject to final determination on liability, stipulated to the damages on the common carrier claim, for amounts that are not material. A trial on the common carrier claim was held during July 2013. On December 9, 2014, the United States District Court for the District of Montana issued an order determining WBI Energy Midstream breached its obligations as a common carrier and ordered judgment in favor of Omimex for the amount of the stipulated damages. WBI Energy Midstream filed an appeal from the United States District Court for the District of Montana's order and judgment.

The Company also is subject to other litigation, and actual and potential claims in the ordinary course of its business which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. Accruals are based on the best information available but actual losses in future periods are affected by various factors making them uncertain. After taking into account liabilities accrued for the foregoing matters, management believes that the outcomes with respect to the above issues and other probable and reasonably possible losses in excess of the amounts accrued, while uncertain, will not have a material effect upon the Company's financial position, results of operations or cash flows.

Environmental matters

Portland Harbor Site In December 2000, Knife River - Northwest was named by the EPA as a PRP in connection with the cleanup of a riverbed site adjacent to a commercial property site acquired by Knife River - Northwest from Georgia-Pacific West, Inc. in 1999. The riverbed site is part of the Portland, Oregon, Harbor Superfund Site. The EPA wants responsible parties to share in the cleanup of sediment contamination in the Willamette River. To date, costs of the overall remedial investigation and feasibility study of the harbor site are being recorded, and initially paid, through an administrative consent order by the LWG, a group of several entities, which does not include Knife River - Northwest or Georgia-Pacific West, Inc. Investigative costs are indicated to be in excess of $100 million . On January 6, 2017, Region 10 of the EPA issued a ROD with its selected remedy for cleanup of the in-river portion of the site. Implementation of the remedy is expected to take up to 13 years with a present value cost estimate of approximately $1 billion . Corrective action will not be taken until remedial design/remedial action plans are approved by the EPA. Knife River - Northwest also received notice in January 2008 that the Portland Harbor Natural Resource Trustee Council intends to perform an injury assessment to natural resources resulting from the release of hazardous substances at the Harbor Superfund Site. The Portland Harbor Natural Resource Trustee Council indicates the injury determination is appropriate to facilitate early settlement of damages and restoration for natural resource injuries. It is not possible to estimate the costs of natural resource damages until an assessment is completed and allocations are undertaken.

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

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

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

The first claim is for contamination at a site in Eugene, Oregon which was received in 1995. There are PRPs in addition to Cascade that may be liable for cleanup of the contamination. Some of these PRPs have shared in the investigation costs. It is expected that these and other PRPs will share in the cleanup costs. Several alternatives for cleanup have been identified, with preliminary cost estimates ranging from approximately $500,000 to $11.0 million . The Oregon DEQ released a ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. It is not known at this time what share of the cleanup costs will actually be borne by

Cascade; however, Cascade anticipates its proportional share could be approximately 50 percent. Cascade has accrued $1.6 million for remediation of this site. In January 2013, the OPUC approved Cascade's application to defer environmental remediation costs at the Eugene site for a period of 12 months starting November 30, 2012. Cascade received orders reauthorizing the deferred accounting for the 12-month periods starting November 30, 2013, December 1, 2014 and December 1, 2015. Cascade has requested authority to defer accounting for the 12-month period starting December 1, 2016, which is pending before the OPUC.

The second claim is for contamination at a site in Bremerton, Washington which was received in 1997. A preliminary investigation has found soil and groundwater at the site contain contaminants requiring further investigation and cleanup. The EPA conducted a Targeted Brownfields Assessment of the site and released a report summarizing the results of that assessment in August 2009. The assessment confirms that contaminants have affected soil and groundwater at the site, as well as sediments in the adjacent Port Washington Narrows. Alternative remediation options have been identified with preliminary cost estimates ranging from $340,000 to $6.4 million . Data developed through the assessment and previous investigations indicates the contamination likely derived from multiple, different sources and multiple current and former owners of properties and businesses in the vicinity of the site may be responsible for the contamination. In April 2010, the Washington DOE issued notice it considered Cascade a PRP for hazardous substances at the site. In May 2012, the EPA added the site to the National Priorities List of Superfund sites. Cascade has entered into an administrative settlement agreement and consent order with the EPA regarding the scope and schedule for a remedial investigation and feasibility study for the site. Cascade has accrued $12.5 million for the remedial investigation, feasibility study and remediation of this site. In April 2010, Cascade filed a petition with the WUTC for authority to defer the costs, which are included in other noncurrent assets, incurred in relation to the environmental remediation of this site. The WUTC approved the petition in September 2010, subject to conditions set forth in the order.

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

Cascade has received notices from and entered into agreement with certain of its insurance carriers that they will participate in defense of Cascade for these contamination claims subject to full and complete reservations of rights and defenses to insurance coverage. To the extent these claims are not covered by insurance, Cascade will seek recovery through the OPUC and WUTC of remediation costs in its natural gas rates charged to customers. The accruals related to these matters are reflected in regulatory assets. For more information, see Note 4 .

Operating leases

The Company leases certain equipment, facilities and land under operating lease agreements. The amounts of annual minimum lease payments due under these leases as of December 31, 2016 , were $51.7 million in 2017 , $43.3 million in 2018 , $33.9 million in 2019 , $23.2 million in 2020 , $9.4 million in 2021 and $42.0 million thereafter. Rent expense was $65.0 million , $53.9 million and $46.9 million for the years ended December 31, 2016 , 2015 and 2014 , respectively.

Purchase commitments

The Company has entered into various commitments, largely construction, natural gas and coal supply, purchased power, natural gas transportation and storage, and service, shipping and construction materials supply contracts, some of which are subject to variability in volume and price. These commitments range from one to 44 years . The commitments under these contracts as of December 31, 2016 , were $367.7 million in 2017 , $215.7 million in 2018 , $189.4 million in 2019 , $138.0 million in 2020 , $130.6 million in 2021 and $859.5 million thereafter. These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2016 , 2015 and 2014 , were $539.3 million , $842.1 million and $759.0 million , respectively.

Guarantees

In June 2016, WBI Energy sold all of the outstanding membership interests in Dakota Prairie Refining. In connection with the sale, Centennial agreed to continue to guarantee certain debt obligations of Dakota Prairie Refining which totaled $63.8 million at December 31, 2016 , and are expected to mature by 2023. Tesoro agreed to indemnify Centennial for any losses and litigation expenses arising from the guarantee. The estimated fair values of the indemnity asset and guarantee liability are reflected in deferred charges and other assets - other and deferred credits and other liabilities - other, respectively, on the Consolidated Balance Sheets. Continuation of the guarantee was required as a condition to the sale of Dakota Prairie Refining.

In March 2016, a sale agreement was signed to sell Fidelity's assets in the Paradox Basin. In connection with the sale, Centennial agreed to guarantee Fidelity's indemnity obligations associated with the Paradox Basin assets. The guarantee was required by the buyer as a condition to the sale of the Paradox Basin assets.

In 2009, multiple sales agreements were signed to sell the Company's ownership interests in the Brazilian Transmission Lines. In connection with the sale, Centennial has agreed to guarantee payment of any indemnity obligations of certain of the Company's indirect wholly owned subsidiaries who are the sellers in three purchase and sale agreements for periods ranging up to 10 years from the date of sale. The guarantees were required by the buyers as a condition to the sale of the Brazilian Transmission Lines.

Certain subsidiaries of the Company have outstanding guarantees to third parties that guarantee the performance of other subsidiaries of the Company. These guarantees are related to construction contracts, insurance deductibles and loss limits, and certain other guarantees. At December 31, 2016 , the fixed maximum amounts guaranteed under these agreements aggregated $98.7 million . The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $33.6 million in 2017 ; $4.5 million in 2018 ; $56.6 million in 2019 ; and $4.0 million , which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2016 . In the event of default under these guarantee obligations, the subsidiary issuing the guarantee for that particular obligation would be required to make payments under its guarantee.

Certain subsidiaries have outstanding letters of credit to third parties related to insurance policies and other agreements, some of which are guaranteed by other subsidiaries of the Company. At December 31, 2016 , the fixed maximum amounts guaranteed under these letters of credit aggregated $30.8 million , all of which expire in 2017. There were no amounts outstanding under the above letters of credit at December 31, 2016 . In the event of default under these letter of credit obligations, the subsidiary issuing the letter of credit for that particular obligation would be required to make payments under its letter of credit.

In addition, Centennial, Knife River and MDU Construction Services have issued guarantees to third parties related to the routine purchase of maintenance items, materials and lease obligations for which no fixed maximum amounts have been specified. These guarantees have no scheduled maturity date. In the event a subsidiary of the Company defaults under these obligations, Centennial, Knife River and MDU Construction Services would be required to make payments under these guarantees. Any amounts outstanding by subsidiaries of the Company for these guarantees were reflected on the Consolidated Balance Sheet at December 31, 2016 .

In the normal course of business, Centennial has surety bonds related to construction contracts and reclamation obligations of its subsidiaries. In the event a subsidiary of Centennial does not fulfill a bonded obligation, Centennial would be responsible to the surety bond company for completion of the bonded contract or obligation. A large portion of the surety bonds is expected to expire within the next 12 months; however, Centennial will likely continue to enter into surety bonds for its subsidiaries in the future. As of December 31, 2016 , approximately $516.1 million of surety bonds were outstanding, which were not reflected on the Consolidated Balance Sheet.

Variable interest entities

The Company evaluates its arrangements and contracts with other entities to determine if they are VIEs and if so, if the Company is the primary beneficiary. For more information, see Note 1 .

Dakota Prairie Refining, LLC On February 7, 2013, WBI Energy and Calumet formed a limited liability company, Dakota Prairie Refining, and entered into an operating agreement to develop, build and operate Dakota Prairie Refinery in southwestern North Dakota. WBI Energy and Calumet each had a 50 percent ownership interest in Dakota Prairie Refining. WBI Energy's and Calumet's capital commitments, based on a total project cost of $300 million , under the agreement were $150 million and $75 million , respectively. Capital commitments in excess of $300 million were shared equally between WBI Energy and Calumet. Dakota Prairie Refining entered into a term loan for project debt financing of $75 million on April 22, 2013. The operating agreement provided for allocation of profits and losses consistent with ownership interests; however, deductions attributable to project financing debt was allocated to Calumet. Calumet's cash distributions from Dakota Prairie Refining were decreased by the principal and interest paid on the project debt, while the cash distributions to WBI Energy were not decreased. Pursuant to the operating agreement, Centennial agreed to guarantee Dakota Prairie Refining's obligation under the term loan. The net loss attributable to noncontrolling interest on the Consolidated Statements of Income is pretax as Dakota Prairie Refining was a limited liability company. For more information related to the guarantee, see Guarantees in this note.

Dakota Prairie Refining was determined to be a VIE, and the Company had determined that it was the primary beneficiary as it had an obligation to absorb losses that could have been potentially significant to the VIE through WBI Energy's equity investment and Centennial's guarantee of the third-party term loan. Accordingly, the Company consolidated Dakota Prairie Refining in its financial statements and recorded a noncontrolling interest for Calumet's ownership interest.

On June 24, 2016, WBI Energy entered into a membership interest purchase agreement with Tesoro to sell all of the outstanding membership interests in Dakota Prairie Refining to Tesoro. To effectuate the sale, WBI Energy acquired Calumet’s 50 percent membership interest in Dakota Prairie Refining on June 27, 2016. The sale of the membership interests to Tesoro closed on June 27, 2016. For more information on the Company's discontinued operations, see Note 2 .

Dakota Prairie Refinery commenced operations in May 2015. The assets of Dakota Prairie Refining were used solely for the benefit of Dakota Prairie Refining. The total assets and liabilities of Dakota Prairie Refining at December 31 were as follows:

		2015
		(In thousands)
Assets		
Current assets:		
Cash and cash equivalents	$	851
Accounts receivable		7,693
Inventories		13,176
Other current assets		6,215
Total current assets		27,935
Net property, plant and equipment		425,123
Deferred charges and other assets:		
Other		9,626
Total deferred charges and other assets		9,626
Total assets	$	462,684
Liabilities		
Current liabilities:		
Short-term borrowings	$	45,500
Long-term debt due within one year		5,250
Accounts payable		24,766
Taxes payable		1,391
Accrued compensation		938
Other accrued liabilities		4,953
Total current liabilities		82,798
Long-term debt		63,750
Total liabilities	$	146,548

Fuel Contract Coyote Station entered into a coal supply agreement with Coyote Creek that provides for the purchase of coal necessary to supply the coal requirements of the Coyote Station for the period May 2016 through December 2040. Coal purchased under the coal supply agreement is reflected in inventories on the Company's Consolidated Balance Sheets and is recovered from customers as a component of fuel and purchased power.

The coal supply agreement creates a variable interest in Coyote Creek due to the transfer of all operating and economic risk to the Coyote Station owners, as the agreement is structured so that the price of the coal will cover all costs of operations as well as future reclamation costs. The Coyote Station owners are also providing a guarantee of the value of the assets of Coyote Creek as they would be required to buy the assets at book value should they terminate the contract prior to the end of the contract term and are providing a guarantee of the value of the equity of Coyote Creek in that they are required to buy the entity at the end of the contract term at equity value. Although the Company has determined that Coyote Creek is a VIE, the Company has concluded that it is not the primary beneficiary of Coyote Creek because the authority to direct the activities of the entity is shared by the four unrelated owners of the Coyote Station, with no primary beneficiary existing. As a result, Coyote Creek is not required to be consolidated in the Company's financial statements.

At December 31, 2016 , the Company's exposure to loss as a result of the Company's involvement with the VIE, based on the Company's ownership percentage was $43.3 million .

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2016 and 2015 :

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2016				
Operating revenues	**$ 860,214**	**$ 1,043,948**	**$ 1,208,567**	**$ 1,016,099**
Operating expenses	**798,229**	**954,983**	**1,061,883**	**904,613**
Operating income	**61,985**	**88,965**	**146,684**	**111,486**
Income from continuing operations	**31,865**	**46,298**	**88,386**	**66,547**
Loss from discontinued operations attributable to the Company, net of tax	**(6,996)**	**(155,451)**	**(5,400)**	**(816)**
Net income (loss) attributable to the Company	**24,869**	**(109,153)**	**82,986**	**65,731**
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	**.16**	**.24**	**.45**	**.34**
Discontinued operations attributable to the Company, net of tax	**(.03)**	**(.80)**	**(.03)**	**—**
Earnings (loss) per common share - basic	**.13**	**(.56)**	**.42**	**.34**
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	**.16**	**.24**	**.45**	**.33**
Discontinued operations attributable to the Company, net of tax	**(.03)**	**(.80)**	**(.03)**	**—**
Earnings (loss) per common share - diluted	**.13**	**(.56)**	**.42**	**.33**
Weighted average common shares outstanding:				
Basic	**195,284**	**195,304**	**195,304**	**195,304**
Diluted	**195,284**	**195,699**	**195,811**	**195,889**
2015				
Operating revenues	$ 860,845	$ 938,039	$ 1,198,342	$ 1,016,826
Operating expenses	810,537	878,330	1,070,514	934,896
Operating income	50,308	59,709	127,828	81,930
Income from continuing operations	20,540	26,061	73,886	55,902
Loss from discontinued operations attributable to the Company, net of tax	(326,457)	(255,665)	(213,334)	(3,368)
Net income (loss) attributable to the Company	(305,917)	(229,604)	(139,448)	52,534
Earnings (loss) per common share - basic:				
Earnings before discontinued operations	.10	.13	.38	.29
Discontinued operations attributable to the Company, net of tax	(1.67)	(1.31)	(1.10)	(.02)
Earnings (loss) per common share - basic	(1.57)	(1.18)	(.72)	.27
Earnings (loss) per common share - diluted:				
Earnings before discontinued operations	.10	.13	.38	.29
Discontinued operations attributable to the Company, net of tax	(1.67)	(1.31)	(1.10)	(.02)
Earnings (loss) per common share - diluted	(1.57)	(1.18)	(.72)	.27
Weighted average common shares outstanding:				
Basic	194,479	194,805	195,151	195,266
Diluted	194,566	194,838	195,169	195,324

Notes:

- Fourth quarter 2016 reflects a reduction to a previously recorded MEPP withdrawal liability of $11.1 million (before tax). For more information, see Note 14 .
- 2015 and first quarter 2016 have been recast to present the results of operations of Dakota Prairie Refining as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former refining segment and do not meet the criteria for income (loss) from discontinued operations.
- First quarter 2015 has been recast to present the results of operations of Fidelity as discontinued operations, other than certain general and administrative costs and interest expense which were previously allocated to the former exploration and production segment and do not meet the criteria for income (loss) from discontinued operations.
- First quarter 2015 reflects a MEPP withdrawal liability of $2.4 million (before tax). For more information, see Note 14 .
- Second quarter 2015 reflects an impairment of coalbed natural gas gathering assets of $3.0 million (before tax). For more information, see Note 1 .
- Third quarter 2015 reflects an impairment of coalbed natural gas gathering assets of $14.1 million (before tax). For more information, see Note 1 .

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

Exploration and Production Activities (Unaudited)

In the second quarter of 2015, the Company began the marketing and sale process of Fidelity with an anticipated sale to occur within one year. Between September 2015 and March 2016, the Company entered into purchase and sale agreements to sell all of Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. At the time the Company committed to a plan to sell Fidelity, the Company stopped the use of the full-cost method of accounting for its oil and natural gas production activities. The assets and liabilities have been classified as held for sale and the results of operations included in income (loss) from discontinued operations, other than certain general and administrative costs and interest expense which do not meet the criteria for income (loss) from discontinued operations. Prior to the asset sales, Fidelity was significantly involved in the development and production of oil and natural gas resources. For more information, see Note 2 .

Previously, Fidelity shared revenues and expenses from the development of specified properties in proportion to its ownership interests. The information that follows includes Fidelity's proportionate share of all its previously owned oil and natural gas interests.

The following table sets forth capitalized costs and accumulated depreciation, depletion and amortization related to oil and natural gas producing activities, prior to Fidelity's assets being held for sale, at December 31:

	2014
	(In thousands)
Subject to amortization	$ 3,205,036
Not subject to amortization	132,141
Total capitalized costs	3,337,177
Less accumulated depreciation, depletion and amortization	1,752,566
Net capitalized costs	$ 1,584,611

Capital expenditures, including those not subject to amortization, related to oil and natural gas producing activities prior to Fidelity's assets being held for sale, excluding the years ended December 31, 2016 and 2015, due to no wells being drilled during that time, were as follows:

Year ended December 31,	2014 *
	(In thousands)
Acquisitions:	
Proved properties	$ 87,919
Unproved properties	138,683
Exploration	16,879
Development	331,400
Total capital expenditures	$ 574,881

* Excludes net reductions to property, plant and equipment related to the recognition of future liabilities for asset retirement obligations associated with the plugging and abandonment of oil and natural gas wells of $9.0 million for the year ended December 31, 2014.

Estimates of proved reserves were prepared in accordance with guidelines established by the industry and the SEC. The estimates are arrived at using actual historical wellhead production trends and/or standard reservoir engineering methods utilizing available geological, geophysical, engineering and economic data. The proved reserve estimates as of December 31, 2015 and 2014, were calculated using SEC Defined Prices. Other factors used in the proved reserve estimates were current estimates of well operating and future development costs (which include asset retirement 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 were prepared by internal engineers assigned to an asset team by geographic area. Senior management reviewed and approved the reserve estimates to ensure they were materially accurate.

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

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2016, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	12,687	211	2,531	13,321
Production	—	—	—	—
Extensions and discoveries	—	—	—	—
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(12,687)	(211)	(2,531)	(13,321)
Revisions of previous estimates	—	—	—	—
Balance at end of year	—	—	—	—

Significant changes in proved reserves for the year ended December 31, 2016, include:

- Sales of proved reserves of (13.3) MMBOE, due to the Company's decision to sell Fidelity and exit the exploration and production business

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2015, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	43,918	7,187	245,011	91,940
Production	(3,286)	(393)	(16,747)	(6,471)
Extensions and discoveries	744	29	681	888
Improved recovery	—	—	—	—
Purchases of proved reserves	—	—	—	—
Sales of proved reserves	(16,474)	(6,864)	(202,560)	(57,097)
Revisions of previous estimates	(12,215)	252	(23,854)	(15,939)
Balance at end of year	12,687	211	2,531	13,321

Significant changes in proved reserves for the year ended December 31, 2015, include:

- Sales of proved reserves of (57.1) MMBOE, primarily due to the Company's decision to sell Fidelity and exit the exploration and production business
- Revisions of previous estimates of (15.9) MMBOE, largely the result of lower commodity prices

The changes in the Company's estimated quantities of proved oil, NGL and natural gas reserves for the year ended December 31, 2014, were as follows:

	Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBOE)
Proved developed and undeveloped reserves:				
Balance at beginning of year	41,019	6,602	198,445	80,695
Production	(4,919)	(609)	(20,822)	(8,998)
Extensions and discoveries	9,654	3,634	64,420	24,025
Improved recovery	—	—	—	—
Purchases of proved reserves	5,463	—	7,711	6,748
Sales of proved reserves	(4,945)	(3,109)	(40,451)	(14,796)
Revisions of previous estimates	(2,354)	669	35,708	4,266
Balance at end of year	43,918	7,187	245,011	91,940

Significant changes in proved reserves for the year ended December 31, 2014, include:

- Extensions and discoveries of 24.0 MMBOE, primarily due to drilling activity at the Company's East Texas, Bakken and Powder River Basin properties

- Purchases of proved reserves of 6.7 MMBOE, primarily due to the purchase of working interests and leasehold positions in the Powder River Basin
- Sales of proved reserves of (14.8) MMBOE, primarily at the Company's South Texas and Bakken properties
- Revisions of previous estimates of 4.3 MMBOE, largely the result of higher natural gas prices and well performance revisions

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

	2016	2015	2014
Proved developed reserves:			
Oil (MBbls)	—	11,380	30,130
NGL (MBbls)	—	144	4,217
Natural Gas (MMcf)	—	2,033	184,437
Total (MBOE)	—	11,865	65,086
PUD reserves:			
Oil (MBbls)	—	1,307	13,788
NGL (MBbls)	—	67	2,970
Natural Gas (MMcf)	—	498	60,574
Total (MBOE)	—	1,456	26,854
Total proved reserves:			
Oil (MBbls)	—	12,687	43,918
NGL (MBbls)	—	211	7,187
Natural Gas (MMcf)	—	2,531	245,011
Total (MBOE)	—	13,321	91,940

As of December 31, 2016 , the Company had no PUD reserves, which is a decrease of 1.5 MMBOE from December 31, 2015 . The decrease relates to the asset sales during 2016.

Definitions

The following abbreviations and acronyms used in Notes to Consolidated Financial Statements are defined below:

Abbreviation or Acronym	
AFUDC	Allowance for funds used during construction
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
Bicent	Bicent Power LLC
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
BOE	One barrel of oil equivalent - determined using the ratio of one barrel of crude oil, condensate or natural gas liquids to six Mcf of natural gas
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines
Calumet	Calumet Specialty Products Partners, L.P.
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
CEM	Colorado Energy Management, LLC, a former direct wholly owned subsidiary of Centennial Resources (sold in the third quarter of 2007)
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's Consolidated EBITDA	Centennial's consolidated net income from continuing operations plus the related interest expense, taxes, depreciation, depletion, amortization of intangibles and any non-cash charge relating to asset impairment for the preceding 12-month period
Centennial Resources	Centennial Energy Resources LLC, a direct wholly owned subsidiary of Centennial
Company	MDU Resources Group, Inc.
Coyote Creek	Coyote Creek Mining Company, LLC, a subsidiary of The North American Coal Corporation
Coyote Station	427-MW coal-fired electric generating facility near Beulah, North Dakota (25 percent ownership)
Dakota Prairie Refinery	20,000-barrel-per-day diesel topping plant built by Dakota Prairie Refining in southwestern North Dakota
Dakota Prairie Refining	Dakota Prairie Refining, LLC, a limited liability company previously owned by WBI Energy and Calumet (previously included in the Company's refining segment)
EBITDA	Earnings before interest, taxes, depreciation, depletion and amortization
EIN	Employer Identification Number
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Fidelity	Fidelity Exploration & Production Company, a direct wholly owned subsidiary of WBI Holdings (previously referred to as the Company's exploration and production segment)
FIP	Funding improvement plan
GAAP	Accounting principles generally accepted in the United States of America
Great Plains	Great Plains Natural Gas Co., a public utility division of the Company
IBEW	International Brotherhood of Electrical Workers
IFRS	International Financial Reporting Standards
Intermountain	Intermountain Gas Company, an indirect wholly owned subsidiary of MDU Energy Capital
IPUC	Idaho Public Utilities Commission
Knife River	Knife River Corporation, a direct wholly owned subsidiary of Centennial
Knife River - Northwest	Knife River Corporation - Northwest, an indirect wholly owned subsidiary of Knife River
K-Plan	Company's 401(k) Retirement Plan
LWG	Lower Willamette Group
MBbls	Thousands of barrels
MBOE	Thousands of BOE
Mcf	Thousand cubic feet
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
MEPP	Multiemployer pension plan

MISO	Midcontinent Independent System Operator, Inc.
MMBOE	Millions of BOE
MMcf	Million cubic feet
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
Montana Seventeenth Judicial District Court	Montana Seventeenth Judicial District Court, Phillips County
MTPSC	Montana Public Service Commission
MW	Megawatt
NDPSC	North Dakota Public Service Commission
NGL	Natural gas liquids
Oil	Includes crude oil and condensate
Omimex	Omimex Canada, Ltd.
OPUC	Oregon Public Utility Commission
Oregon DEQ	Oregon State Department of Environmental Quality
Pronghorn	Natural gas processing plant located near Belfield, North Dakota (WBI Energy Midstream previously held a 50 percent non-operating ownership interest)
PRP	Potentially Responsible Party
PUD	Proved undeveloped
ROD	Record of Decision
RP	Rehabilitation plan
SEC	United States Securities and Exchange Commission
SEC Defined Prices	The average price of oil and natural gas 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
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
Tesoro	Tesoro Refining & Marketing Company LLC
Tesoro Logistics	QEP Field Services, LLC doing business as Tesoro Logistics Rockies LLC
United States District Court for the District of Montana	United States District Court for the District of Montana, Great Falls Division
VIE	Variable interest entity
WBI Energy	WBI Energy, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Midstream	WBI Energy Midstream, LLC, an indirect wholly owned subsidiary of WBI Holdings
WBI Energy Transmission	WBI Energy Transmission, Inc., an indirect wholly owned subsidiary of WBI Holdings
WBI Holdings	WBI Holdings, Inc., a direct wholly owned subsidiary of Centennial
WUTC	Washington Utilities and Transportation Commission
Wygen III	100-MW coal-fired electric generating facility near Gillette, Wyoming (25 percent ownership)
WYPSC	Wyoming Public Service Commission

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

None.

Item 9A. Controls and Procedures

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

Evaluation of Disclosure Controls and Procedures

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

Changes in Internal Controls

No change in the Company's internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) occurred during the quarter ended December 31, 2016 , that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

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

Attestation Report of the Registered Public Accounting Firm

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

Item 9B. Other Information

None.

Item 10. Directors, Executive Officers and Corporate Governance

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 11. Executive Compensation

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

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

Equity Compensation Plan Information

The following table includes information as of December 31, 2016, with respect to the Company's equity compensation plans:

Plan Category	(a) Number of securities to be issued upon exercise of outstanding options, warrants and rights		(b) Weighted average exercise price of outstanding options, warrants and rights		(c) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))	
Equity compensation plans approved by stockholders (1)	664,188	(2)	$ —	(3)	4,824,267	(4)(5)
Equity compensation plans not approved by stockholders	N/A		N/A		N/A	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan, the Long-Term Performance-Based Incentive Plan and the Non-Employee Director Stock Compensation Plan.
(2) Consists of performance shares.
(3) No weighted average exercise price is shown for the performance shares.
(4) 357,757 shares remain available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards. 4,429,239 shares under the Long-Term Performance-Based Incentive Plan remain available for future issuance in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.
(5) This amount also includes 37,271 shares available for issuance under the Non-Employee Director Stock Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors are awarded shares equal in value to $110,000 annually. A non-employee director may acquire additional shares under the plan in lieu of receiving the cash portion of the director's retainer or fees.

The remaining information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

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

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 14. Principal Accountant Fees and Services

Information required by this item is included in the Company's Proxy Statement, which is incorporated herein by reference.

Item 15. Exhibits and Financial Statement Schedules

(a) Financial Statements, Financial Statement Schedules and Exhibits

Index to Financial Statements and Financial Statement Schedules

1. Financial Statements

2. Financial Statement Schedules

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

Years ended December 31,	2016	2015	2014
		(In thousands)	
Operating revenues	**$ 561,266**	$ 556,112	$ 628,578
Operating expenses	**469,062**	478,198	547,820
Operating income	**92,204**	77,914	80,758
Other income	**1,491**	8,318	5,271
Interest expense	**31,519**	23,562	21,055
Income before income taxes	**62,176**	62,670	64,974
Income taxes	**6,355**	15,882	16,819
Equity in earnings of subsidiaries from continuing operations	**177,275**	129,601	136,872
Net income from continuing operations	**233,096**	176,389	185,027
Equity in earnings (loss) of subsidiaries from discontinued operations attributable to the Company	**(168,663)**	(798,824)	113,206
Dividends declared on preferred stocks	**685**	685	685
Earnings (loss) on common stock	**$ 63,748**	$ (623,120)	$ 297,548
Comprehensive income (loss)	**$ 65,848**	$ (617,480)	$ 294,335

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

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

December 31,	2016	2015
	(In thousands, except shares and per share amounts)	
Assets		
Current assets:		
Cash and cash equivalents	$ 4,159	$ 2,921
Receivables, net	80,467	70,511
Accounts receivable from subsidiaries	34,424	33,129
Inventories	17,352	16,883
Prepayments and other current assets	24,531	7,876
Total current assets	160,933	131,320
Investments	70,370	66,784
Investment in subsidiaries	1,603,874	1,722,351
Property, plant and equipment	2,502,264	2,378,994
Less accumulated depreciation, depletion and amortization	756,191	711,209
Net property, plant and equipment	1,746,073	1,667,785
Deferred charges and other assets:		
Goodwill	4,812	4,812
Other	183,654	184,080
Total deferred charges and other assets	188,466	188,892
Total assets	$ 3,769,716	$ 3,777,132
Liabilities and Stockholders' Equity		
Current liabilities:		
Long-term debt due within one year	$ 110	$ 109
Accounts payable	37,697	54,275
Accounts payable to subsidiaries	5,592	6,622
Taxes payable	14,992	10,995
Dividends payable	37,767	36,784
Accrued compensation	16,086	7,539
Other accrued liabilities	34,929	40,931
Total current liabilities	147,173	157,255
Long-term debt	679,667	623,048
Deferred credits and other liabilities:		
Deferred income taxes	270,126	255,069
Other	356,506	345,255
Total deferred credits and other liabilities	626,632	600,324
Commitments and contingencies		
Stockholders' equity:		
Preferred stocks	15,000	15,000
Common stockholders' equity:		
Common stock		
Authorized - 500,000,000 shares, $1.00 par value		
Issued - 195,843,297 shares in 2016 and 195,804,665 shares in 2015	195,843	195,805
Other paid-in capital	1,232,478	1,230,119
Retained earnings	912,282	996,355
Accumulated other comprehensive loss	(35,733)	(37,148)
Treasury stock at cost - 538,921 shares	(3,626)	(3,626)
Total common stockholders' equity	2,301,244	2,381,505
Total stockholders' equity	2,316,244	2,396,505
Total liabilities and stockholders' equity	$ 3,769,716	$ 3,777,132

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

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

Years ended December 31,	2016	2015	2014
		(In thousands)	
Net cash provided by operating activities	$ 238,125	$ 255,273	$ 208,208
Investing activities:			
Capital expenditures	(159,570)	(349,985)	(223,251)
Net proceeds from sale or disposition of property and other	3,784	3,268	1,552
Investments in and advances to subsidiaries	(5,000)	(7,000)	(134,451)
Advances from subsidiaries	15,000	100,000	64,500
Investments	(129)	5	(794)
Net cash used in investing activities	(145,915)	(253,712)	(292,444)
Financing activities:			
Issuance of long-term debt	106,420	224,185	148,959
Repayment of long-term debt	(50,010)	(108,008)	(76,432)
Proceeds from issuance of common stock	—	21,898	150,060
Dividends paid	(147,156)	(142,835)	(136,712)
Excess tax benefit on stock-based compensation	—	—	3,326
Tax withholding on stock-based compensation	(226)	—	(3,896)
Net cash provided by (used in) financing activities	(90,972)	(4,760)	85,305
Increase (decrease) in cash and cash equivalents	1,238	(3,199)	1,069
Cash and cash equivalents - beginning of year	2,921	6,120	5,051
Cash and cash equivalents - end of year	$ 4,159	$ 2,921	$ 6,120

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

Notes to Condensed Financial Statements

Note 1 - Summary of Significant Accounting Policies

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

Earnings (loss) per common share Please refer to the Consolidated Statements of Income of the registrant for earnings (loss) per common share. In addition, see Item 8 - Note 1 for information on the computation of earnings (loss) per common share.

Note 2 - Debt The Company has long-term debt obligations outstanding of $681.8 million at December 31, 2016 , with annual maturities of $100,000 in 2017 , $100.1 million in 2018 , $111.1 million in 2019 , $100,000 in 2020 and $470.4 million scheduled to mature in years after 2021 .

For more information on debt, see Item 8 - Note 6 .

Note 3 - Dividends The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on common stock. Cash dividends paid to the Company by subsidiaries were $115.8 million , $110.6 million and $105.6 million for the years ended December 31, 2016 , 2015 and 2014 , respectively.

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

For the years ended December 31, 2016 , 2015 and 2014

Description	Balance at Beginning of Year	Additions: Charged to Costs and Expenses	Additions: Other *	Deductions **	Balance at End of Year
			(In thousands)		
Allowance for doubtful accounts:					
2016	**$ 9,835**	**$ 8,302**	**$ 851**	**$ 8,509**	**$ 10,479**
2015	9,511	11,343	1,012	12,031	9,835
2014	10,085	8,548	1,335	10,457	9,511

* Recoveries.
** Uncollectible accounts written off.

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

3. Exhibits

2(a) Membership Interest Purchase Agreement, dated as of June 24, 2016, between WBI Energy, Inc. and Tesoro Refining & Marketing Company LLC, filed as Exhibit 2.1 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016, in File No. 1-3480*

2(b) Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P., filed as Exhibit 2.2 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016, in File No. 1-3480*

2(c) Amendment No. 1 to Purchase and Sale Agreement, dated as of June 9, 2016, by and among Calumet North Dakota, LLC, WBI Energy, Inc., and as applicable, MDU Resources Group, Inc., Centennial Energy Holdings, Inc., and Calumet Specialty Products Partners, L.P., filed as Exhibit 2.3 to Form 8-K/A dated June 24, 2016, filed on July 21, 2016, in File No. 1-3480*

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

3(b) Bylaws of MDU Resources Group, Inc., as amended and restated on February 16, 2017, filed as Exhibit 3.1 to Form 8-K dated February 16, 2017, filed on February 21, 2017, in File No. 1-3480*

4(a) Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee, filed as Exhibit 4(f) to Form S-8 on January 21, 2004, in Registration No. 333-112035*

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

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

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

4(e) Letter Amendment No. 2 to Amended and Restated Master Shelf Agreement, dated December 19, 2007, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2015, filed on February 19, 2016, in File No. 1-3480*

4(f) Letter Amendment No. 3 to Amended and Restated Master Shelf Agreement, dated December 18, 2015, among Centennial Energy Holdings, Inc., the Prudential Insurance Company of America, and certain investors described in the Letter Amendment, filed as Exhibit 4(f) to Form 10-K for the year ended December 31, 2015, filed on February 19, 2016, in File No. 1-3480*

4(g) MDU Resources Group, Inc. Credit Agreement, dated May 26, 2011, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4(e) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

4(h)	First Amendment to Credit Agreement, dated October 4, 2012, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4 to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*
4(i)	Second Amendment to Credit Agreement, dated May 8, 2014, among MDU Resources Group, Inc., Various Lenders, and Wells Fargo Bank, National Association, as Administrative Agent, filed as Exhibit 4(a) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*
4(j)	Third Amended and Restated Credit Agreement, dated May 8, 2014, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto, filed as Exhibit 4(b) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*
4(k)	Fourth Amended and Restated Credit Agreement, dated as of September 23, 2016, among Centennial Energy Holdings, Inc., U.S. Bank National Association, as Administrative Agent, and The Several Financial Institutions party thereto, filed as Exhibit 4 to Form 10-Q for the quarter ended September 30, 2016, filed on November 7, 2016, in File No. 1-3480*
4(l)	MDU Energy Capital, LLC Master Shelf Agreement, dated as of August 9, 2007, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America and the holders of the notes thereunder, filed as Exhibit 4 to Form 8-K dated August 16, 2007, filed on August 16, 2007, in File No. 1-3480*
4(m)	Amendment No. 1 to Master Shelf Agreement, dated October 1, 2008, among MDU Energy Capital, LLC, Prudential Investment Management, Inc., the Prudential Insurance Company of America, and the holders of the notes thereunder, filed as Exhibit 4(b) to Form 10-Q for the quarter ended September 30, 2008, filed on November 5, 2008, in File No. 1-3480*
4(n)	Indenture dated as of August 1, 1992, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 8-K dated August 12, 1992, in File No. 1-7196*
4(o)	First Supplemental Indenture dated as of October 25, 1993, between Cascade Natural Gas Corporation and The Bank of New York relating to Medium-Term Notes and the 7.5% Notes due November 15, 2031, filed by Cascade Natural Gas Corporation as Exhibit 4 to Form 10-Q for the quarter ended June 30, 1993, in File No. 1-7196*
4(p)	Second Supplemental Indenture, dated January 25, 2005, between Cascade Natural Gas Corporation and The Bank of New York, as trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated January 25, 2005, filed on January 26, 2005, in File No. 1-7196*
4(q)	Third Supplemental Indenture dated as of March 8, 2007, between Cascade Natural Gas Corporation and The Bank of New York Trust Company, N.A., as Successor Trustee, filed by Cascade Natural Gas Corporation as Exhibit 4.1 to Form 8-K dated March 8, 2007, filed on March 8, 2007, in File No. 1-7196*
+10(a)	MDU Resources Group, Inc. Supplemental Income Security Plan, as amended and restated February 11, 2016, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2016, filed on May 6, 2016, in File No. 1-3480*
+10(b)	Director Compensation Policy, as amended May 15, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*
+10(c)	Deferred Compensation Plan for Directors, as amended May 15, 2008, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2008, filed on August 7, 2008, in File No. 1-3480*
+10(d)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*
+10(e)	MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*
+10(f)	MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, as amended February 11, 2016, filed as Exhibit 10(f) to Form 10-K for the year ended December 31, 2015, filed on February 19, 2016, in File No. 1-3480*
+10(g)	MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended February 11, 2016, and Rules and Regulations, as amended March 4, 2013, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2016, filed on May 6, 2016, in File No. 1-3480*
+10(h)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 12, 2014, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*
+10(i)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 11, 2015, filed as Exhibit 10.3 to Form 8-K dated February 11, 2015, filed on February 18, 2015, in File No. 1-3480*
+10(j)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016, filed as Exhibit 10.3 to Form 8-K dated February 10, 2016, filed on February 18, 2016, in File No. 1-3480*
+10(k)	Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016, filed as Exhibit 10.2 to Form 8-K dated February 10, 2016, filed on February 18, 2016, in File No. 1-3480*

+10(l) Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, filed as Exhibit 10.1 to Form 8-K dated May 15, 2014, filed on May 15, 2014, in File No. 1-3480*

+10(m) Form of Amendment No. 1 to Indemnification Agreement, filed as Exhibit 10.2 to Form 8-K dated May 15, 2014, filed on May 15, 2014, in File No. 1-3480*

+10(n) MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of January 27, 2017**

+10(o) MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as amended and restated November 17, 2016, filed as Exhibit 10.1 to Form 8-K dated November 17, 2016, filed on November 21, 2016, in File No. 1-3480*

+10(p) MDU Resources Group, Inc. 401(k) Retirement Plan, as restated March 1, 2011, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

+10(q) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 29, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2011, filed on May 5, 2011, in File No. 1-3480*

+10(r) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2011, filed as Exhibit 10(d) to Form 10-Q for the quarter ended June 30, 2011, filed on August 5, 2011, in File No. 1-3480*

+10(s) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2011, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2011, filed on November 4, 2011, in File No. 1-3480*

+10(t) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2011, filed as Exhibit 10(ac) to Form 10-K for the year ended December 31, 2011, filed on February 24, 2012, in File No. 1-3480*

+10(u) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated May 24, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended June 30, 2012, filed on August 7, 2012, in File No. 1-3480*

+10(v) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

+10(w) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 29, 2012, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2012, filed on November 7, 2012, in File No. 1-3480*

+10(x) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 19, 2012, filed as Exhibit 10(z) to Form 10-K for the year ended December 31, 2012, filed on February 28, 2013, in File No. 1-3480*

+10(y) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(z) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 9, 2013, filed as Exhibit 10(c) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(aa) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 23, 2013, filed as Exhibit 10(d) to Form 10-Q for the quarter ended September 30, 2013, filed on November 7, 2013, in File No. 1-3480*

+10(ab) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 31, 2013, filed as Exhibit 10(aa) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*

+10(ac) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2014, filed on May 7, 2014, in File No. 1-3480*

+10(ad) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 5, 2014, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014, in File No. 1-3480*

+10(ae) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated July 7, 2014, filed as Exhibit 4.20 to Form S-8, filed on August 26, 2014, in Registration No. 333-198364*

+10(af) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 18, 2014, filed as Exhibit 4.21 to Form S-8, filed on August 26, 2014, in Registration No. 333-198364*

+10(ag) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 30, 2014, filed as Exhibit 10(b) to Form 10-Q for the quarter ended September 30, 2014, filed on November 7, 2014, in File No. 1-3480*

+10(ah) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated November 25, 2014, filed as Exhibit 10(ah) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(ai) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 11, 2014, filed as Exhibit 10(ai) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(aj) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 11, 2014, filed as Exhibit 10(aj) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(ak) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 30, 2014, filed as Exhibit 10(ak) to Form 10-K for the year ended December 31, 2014, filed on February 20, 2015, in File No. 1-3480*

+10(al) Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated February 17, 2015, filed as Exhibit 10(a) to Form 10-Q for the quarter ended March 31, 2015, filed on May 8, 2015, in File No. 1-3480*

+10(am)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 13, 2015, filed as Exhibit 10(b) to Form 10-Q for the quarter ended March 31, 2015, filed on May 8, 2015, in File No. 1-3480*
+10(an)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated June 30, 2015, filed as Exhibit 10(a) to Form 10-Q for the quarter ended June 30, 2015, filed on August 4, 2015, in File No. 1-3480*
+10(ao)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated November 19, 2015, filed as Exhibit 10(ap) to Form 10-K for the year ended December 31, 2015, filed on February 19, 2016, in File No. 1-3480*
+10(ap)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated January 22, 2016, filed as Exhibit 10(c) to Form 10-Q for the quarter ended March 31, 2016, filed on May 6, 2016, in File No. 1-3480*
+10(aq)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 10, 2016, filed as Exhibit 10(d) to Form 10-Q for the quarter ended March 31, 2016, filed on May 6, 2016, in File No. 1-3480*
+10(ar)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated September 19, 2016, filed as Exhibit 10(a) to Form 10-Q for the quarter ended September 30, 2016, filed on November 7, 2016, in File No. 1-3480*
+10(as)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated December 29, 2016**
+10(at)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013, filed as Exhibit 10(ab) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*
+10(au)	Martin A. Fritz Offer Letter, dated July 1, 2015, filed as Exhibit 10.2 to Form 8-K dated June 30, 2015, filed on July 2, 2015, in File No. 1-3480*
+10(av)	Jason L. Vollmer Offer Letter, dated March 7, 2016, filed as Exhibit 10.2 to Form 8-K dated March 2, 2016, file on March 8, 2016, in file No. 1-3480*
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends**
21	Subsidiaries of MDU Resources Group, Inc.**
23	Consent of Independent Registered Public Accounting Firm**
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002**
32	Certification of Chief Executive Officer and Chief Financial Officer furnished pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002**
95	Mine Safety Disclosures**
99(a)	Equity Distribution Agreement entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 1 to Form 8-K dated May 20, 2013, filed on May 20, 2013, in File No. 1-3480*
99(b)	First Amendment to Equity Distribution Agreement, dated December 2, 2013, entered into between MDU Resources Group, Inc. and Wells Fargo Securities, LLC, filed as Exhibit 99(c) to Form 10-K for the year ended December 31, 2013, filed on February 21, 2014, in File No. 1-3480*
101	The following materials from MDU Resources Group, Inc.'s Annual Report on Form 10-K for the year ended December 31, 2016, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Statements of Income, (ii) the Consolidated Statements of Comprehensive Income, (iii) the Consolidated Balance Sheets, (iv) the Consolidated Statements of Equity, (v) the Consolidated Statements of Cash Flows, (vi) the Notes to Consolidated Financial Statements, tagged in summary and detail, (vii) Schedule I - Condensed Financial Information of Registrant, tagged in summary and detail and (viii) Schedule II - Consolidated Valuation and Qualifying Accounts, tagged in summary and detail

* Incorporated herein by reference as indicated.

** Filed herewith.

\+ Management contract, compensatory plan or arrangement.

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

Signatures

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

MDU Resources Group, Inc.

Date: February 24, 2017 By: /s/ David L. Goodin
David L. Goodin
(President and Chief Executive Officer)

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

Signature	Title	Date
/s/ David L. Goodin David L. Goodin (President and Chief Executive Officer)	Chief Executive Officer and Director	February 24, 2017
/s/ Doran N. Schwartz Doran N. Schwartz (Vice President and Chief Financial Officer)	Chief Financial Officer	February 24, 2017
/s/ Jason L. Vollmer Jason L. Vollmer (Vice President, Chief Accounting Officer and Treasurer)	Chief Accounting Officer	February 24, 2017
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 24, 2017
/s/ Thomas Everist Thomas Everist	Director	February 24, 2017
/s/ Karen B. Fagg Karen B. Fagg	Director	February 24, 2017
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 24, 2017
/s/ A. Bart Holaday A. Bart Holaday	Director	February 24, 2017
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 24, 2017
/s/ William E. McCracken William E. McCracken	Director	February 24, 2017
/s/ Patricia L. Moss Patricia L. Moss	Director	February 24, 2017
/s/ John K. Wilson John K. Wilson	Director	February 24, 2017

MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart

Section 16 Officers

Name	**Title**	**Date of Agreement**
David L. Goodin	President and Chief Executive Officer, MDU Resources Group, Inc.	August 12, 2010, as amended May 15, 2014
Doran N. Schwartz	Vice President and Chief Financial Officer, MDU Resources Group, Inc.	August 12, 2010, as amended May 15, 2014
Nicole A. Kivisto	President and Chief Executive Officer, Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Cascade Natural Gas Corporation, and Intermountain Gas Company	August 12, 2010, as amended May 15, 2014
David C. Barney	President and Chief Executive Officer, Knife River Corporation	May 16, 2013, as amended May 15, 2014
Jeffrey S. Thiede	President and Chief Executive Officer, MDU Construction Services Group, Inc.	May 16, 2013, as amended May 15, 2014
Dennis L. Haider	Executive Vice President – Business Development, MDU Resources Group, Inc.	June 1, 2013, as amended May 15, 2014
Jason L. Vollmer	Vice President, Chief Accounting Officer and Treasurer, MDU Resources Group, Inc.	November 29, 2014
Martin A. Fritz	President and Chief Executive Officer, WBI Holdings, Inc.	July 20, 2015
Daniel S. Kuntz	Vice President, General Counsel and Secretary, MDU Resources Group, Inc.	November 18, 2015
Anne M. Jones	Vice President – Human Resources, MDU Resources Group, Inc.	January 1, 2016
Margaret (Peggy) A. Link	Chief Information Officer	January 1, 2017

Directors

Name	Title	Date of Agreement
Harry J. Pearce	Director and Chairman of the Board	August 12, 2010
David L. Goodin	Director	August 12, 2010
Thomas Everist	Director	August 12, 2010
Karen B. Fagg	Director	August 12, 2010
Mark A. Hellerstein	Director	August 1, 2013
A. Bart Holaday	Director	August 12, 2010
Dennis W. Johnson	Director	August 12, 2010
William E. McCracken	Director	August 1, 2013
Patricia L. Moss	Director	August 12, 2010
John K. Wilson	Director	August 12, 2010

INSTRUMENT OF AMENDMENT TO THE
MDU RESOURCES GROUP, INC.
401(k) RETIREMENT PLAN

The MDU Resources Group, Inc. 401(k) Retirement Plan (as amended and restated March 1, 2011) (the "K-Plan"), is hereby further amended, as follows:

1. Effective January 1, 2017, by replacing Section 3.1 Savings Contributions, of Article III, Contributions, in its entirety, with the following:

3.1 Savings Contributions

(a) Maximum. A Participant may contribute, by payroll deduction, any whole percentage of the Participant's Compensation for each pay period to the Participant's Savings Contribution Account, subject to the following maximum percentages: (i) 50% of the Participant's Compensation if the Participant is not a Highly Compensated Employee, and (ii) 22% of the Participant's Compensation if the Participant is a Highly Compensated Employee.

(b) Savings contributions on behalf of a Participant shall constitute Employer contributions to the Plan and shall be credited to such Participant's Savings Contribution Account, subject to Section 3.5. An Employer may withhold a Participant's Savings Contributions from any portion of the Participant's taxable income (without regard to whether such taxable income constitutes "Compensation" under the Plan) so long as the applicable deferral limits set forth in Section 3.1(a) above are not exceeded.

(c) Upon becoming a Participant, and at any time thereafter, each Participant may elect the percentage of Compensation to be contributed as a Savings Contribution to the Plan. Any such election will take effect as soon as administratively feasible. Each election by a Participant under this Section shall be made pursuant to the method established by the Committee for this purpose.

(d) Effective September 1, 2007, if a Participant fails to make an election within thirty (30) days of becoming a Participant, the Participant shall be deemed to have elected to have three percent (3%) of Compensation withheld and contributed to the Plan, effective as soon as administratively feasible following the thirty (30) day period. Prior to the date an automatic deferral election is effective, the Participant shall receive a notice that explains the automatic deferral feature, the Eligible Employee's right to elect not to have Compensation automatically reduced, and the procedure for making an alternate election. An automatic deferral election shall be treated, for all purposes of the Plan, as a voluntary deferral election.

In addition, each Eligible Employee who did not have a Savings Contribution election of at least three percent (3%) of Compensation on file as of May 25, 2007, shall be deemed to have elected to have three percent (3%) of Compensation withheld and contributed to the Plan as Savings Contributions effective as of the first payroll period beginning after the Effective Date, unless prior to August 21, 2007, such Eligible Employee has made an alternate election.

(e) Effective January 1, 2017, if a Participant fails to make an election within thirty (30) days of becoming a Participant, the Participant shall be deemed to have elected to have four percent (4%) of Compensation withheld and contributed to the Plan, effective as soon as administratively feasible following the thirty (30) day period. Prior to the date an automatic deferral election is effective, the Participant shall receive a notice that explains the automatic deferral feature, the Eligible Employee's right to elect not to have Compensation automatically reduced, and the procedure for making an alternate election. An automatic deferral election shall be treated, for all purposes of the Plan, as a voluntary deferral election.

(f) Notwithstanding a Participant's election under Subsection 3.1(c) or deemed election under Subsection 3.1(d) or (e) above, each Participant who is contributing less than fifteen percent (15%) of Compensation to the Plan on January 16, 2012, and January 1 of each year thereafter, shall be deemed to have elected to increase the Participant's deferral percentage by one percent (1%) on and after March 1, 2012, and January 1 of each year thereafter; provided, however, that this Subsection 3.1(f) shall not apply to any Participant who has elected to opt out of the automatic deferral escalation feature.

(g) Savings Contributions must be contributed to the Trust Fund as soon as practicable, but in no event later than the fifteenth (15th) business day of the month following the month in which such deferrals were made. Savings Contributions made pursuant to Subsection 3.1(d), (e), or (f) above shall be invested pursuant to Subsection 5.2(a) below.

Explanation: This amendment increases the automatic enrollment deferral rate from 3% to 4% for newly eligible employees, effective January 1, 2017.

2. Effective January 1, 2017, by replacing the final paragraph of the Introduction , in its entirety, with the following:

On February 7, 2013, MDU Resources Group, Inc., through its wholly-owned subsidiary, WBI Energy, Inc., ("WBI Energy") formed Dakota Prairie Refining, LLC ("Dakota Prairie"). WBI Energy owns 50% of the membership interests of Dakota Prairie and Calumet North Dakota, LLC ("Calumet") owns 50% of the membership interests of Dakota Prairie. Calumet and consequently Dakota Prairie are not members of the MDU Resources Group, Inc. controlled group of corporations within the meaning of Section 414(b) of the Code. Effective September 9, 2013, Dakota Prairie adopted the Plan for its eligible employees. Thereafter, with respect to Dakota Prairie, the Plan is maintained as a multiple employer plan (as defined in Section 413(c) of the Code) in accordance with Supplement I. On June 28, 2016, Dakota Prairie was sold. Effective January 1, 2017, the Plan shall revert to and be maintained as a single employer plan.

Explanation: This amendment reverts the K-Plan back to a single employer plan, effective January 1, 2017, pursuant to the sale of Dakota Prairie on June 28, 2016.

3. Effective January 1, 2016, by deleting the last sentence of the defined term "Investment Funds" in Article I, Definitions .

4. Effective January 1, 2016, by adding the following new paragraph (d) to Section 5.2, Investment :

(d) One of the Investment Funds shall be a fund invested primarily in Common Stock (the "Common Stock Investment Fund"). The Common Stock Investment Fund is intended to be a permanent Investment Fund under the Plan, unless the Committee concludes that it is clearly imprudent to continue the Common Stock Investment Fund as an Investment Fund under the Plan. The Committee will evaluate the prudence of maintaining the Common Stock Investment Fund not on the basis of the risk of the Common Stock Investment Fund standing alone, but in light of the availability of other Investment Funds under the Plan and the ability of Participants and beneficiaries to construct a diversified investment portfolio consistent with their individual desired level of risk and return.

Explanation: Amendments 3 and 4 reflect a recent best practice with respect to company stock funds.

5. Effective June 28, 2016, by removing Supplement D-8, Provisions Relating to the Dakota Prairie Refining, LLC Retirement Contribution Feature , in its entirety.

Explanation: This amendment removes the Retirement Contribution Feature for Dakota Prairie, pursuant to the sale of Dakota Prairie on June 28, 2016.

6. Effective January 1, 2017, by adding the following section to Supplement I, Multiple Employer Plan Provisions Applicable Upon Adoption of the Plan by Dakota Prairie Refining, LLC :

I-6 Reversion to Single Employer Plan . Dakota Prairie was sold on June 28, 2016. As a result of this sale, Dakota Prairie is no longer a Participating Affiliate in the Plan. Therefore, effective January 1, 2017, this Supplement I is no longer applicable.

Explanation: This amendment changes Supplement I to reflect that it is no longer applicable, effective January 1, 2017, pursuant to the sale of Dakota Prairie on June 28, 2016.

7. Effective January 1, 2017, by replacing Section D-1-2 Eligibility to Share in the Profit Sharing Feature of Supplement D-1, Provisions Relating to the Profit Sharing Feature for Certain Participating Affiliates , in its entirety, with the following:

Eligibility to Share in the Profit Sharing Feature. Participation in the Profit Sharing Feature(s) for any Plan Year is limited to employees of the Supplement D-1 Company who satisfy the Plan's definition of Eligible Employee (unless otherwise noted below). The current and original effective dates for each Participating Affiliate's respective Profit Sharing Feature are listed below.

Participating Affiliate	**Current Effective Date (Original Effective Date)** [2]
Ames Sand & Gravel, Inc.	January 1, 2016 (July 16, 2007)
Anchorage Sand & Gravel Company, Inc. (excluding President)	January 1, 1999
Baldwin Contracting Company, Inc.	January 1, 1999
Capital Electric Line Builders, Inc. [7]	January 1, 2014
Cascade Natural Gas Corporation [1]	January 1, 2017 (July 2, 2007)
Concrete, Inc.	January 1, 2001
Connolly-Pacific Co.	January 1, 2007
DSS Company	January 1, 2004 (July 8, 1999)
E.S.I., Inc.	January 1, 2008 (January 1, 2003)
Fairbanks Materials, Inc.	May 1, 2008
Granite City Ready Mix, Inc.	June 1, 2002
Great Plains Natural Gas Co. [1]	January 1, 2017 (January 1, 2008)
Hawaiian Cement (non-union employees hired after December 31, 2005)	January 1, 2009
Intermountain Gas Company [1]	January 1, 2017 (January 1, 2011)

Participating Affiliate	Current Effective Date (Original Effective Date) [2]
JTL Group, Inc. [5/6]	January 1, 2015 (January 1, 2014)
Jebro Incorporated	November 1, 2005
Kent's Oil Service [4]	January 1, 2007
Knife River – North Dakota Division, a Division of Knife River Corporation – North Central	January 1, 2016 (January 1, 2007)
Knife River Corporation – North Central	January 1, 2016 (January 1, 2007)
Knife River Corporation – Northwest (the Central Oregon Division, f/k/a HTS)	January 1, 2010 (January 1, 1999)
Knife River Corporation – Northwest (the Idaho Division)	January 1, 2015
Knife River Corporation – Northwest (the Southern Oregon Division)	January 1, 2012
Knife River Corporation – Northwest (the Western Oregon Division)	January 1, 2012
Knife River Corporation - South (f/k/a Young Contractors, Inc.)	January 1, 2008 (January 1, 2007)
Knife River Midwest, LLC	January 1, 2016 (April 1, 2004)
LTM, Incorporated	January 1, 2003
MDU Resources Group, Inc. [1]	January 1, 2017
Montana-Dakota Utilities Co. (non-union employees) [1]	January 1, 2017 (January 1, 2008)
Montana-Dakota Utilities Co. (union employees)	January 1, 2008
Northstar Materials, Inc.	January 1, 2016 (January 1, 2003)

Participating Affiliate	Current Effective Date (Original Effective Date) [2]
On Electric Group, Inc. [3]	March 7, 2011
Wagner Industrial Electric, Inc.	January 1, 2008
Wagner Smith Equipment Co.	January 1, 2008 (July 1, 2000)
WBI Energy, Inc. [1]	January 1, 2017 (May 1, 2012)
WBI Energy Midstream, LLC [1]	January 1, 2017 (January 1, 2001)
WBI Energy Transmission, Inc. [1]	January 1, 2017 (January 1, 2009)
WHC, Ltd.	September 1, 2001

1/ Eligible employees only include those in salary grade levels 29-38.

2/ In the event a Participating Affiliate adopts a Profit Sharing Feature on a date other than January 1, effective as of the date of participation in the Plan, the amount of any such contribution allocated to a Supplement D-1 Participant shall be based upon Compensation, received while in the employ of the Participating Affiliate after the date of acquisition by the Company or any Affiliate.

3/ Requirement to be an Active Employee on the last day of the Plan Year does not apply.

4/ The following participant of Kent's Oil Service is granted vesting service for prior years of service with Spirit Road Oils: Jose Padilla.

5/ Eligible JTL Casper hourly employees (both union and nonunion), including those employees who participate in the Operating Engineers Local No. 800 & The Wyoming Contractors' Association, Inc. Pension Trust Fund for Wyoming (JTL MEP employees.)

6/ Eligible salaried employees of JTL hired after December 31, 2014 or any other JTL employee who transfers to a salaried position after December 31, 2014.

7/ Eligible employees participating in a management incentive compensation plan are not eligible for a Profit Sharing Contribution.

In order to share in the allocation of any profit sharing contribution made by a Supplement D-1 Company pursuant to Paragraph 3 below for a given Plan Year, Participants employed by a Supplement D-1 Company must be credited with 1,000 Hours of Service (prorated for the Plan Year in which the Profit Sharing Feature becomes effective) in that Plan Year, be an Active Employee of the Supplement D-1 Company on the last day of the Plan Year, and must not be covered by a collectively bargained unit to which the Profit Sharing has not been extended.

However, an Eligible Employee of a Knife River Corporation Participating Affiliate who transfers during the Plan Year and remains employed by a Knife River Corporation Participating Affiliate on the last day of the Plan Year will be eligible to receive a prorated profit sharing contribution from each Knife River Corporation Participating

Affiliate.

Moreover, effective January 1, 2009, an Eligible Employee of Montana-Dakota Utilities Co., Great Plains Natural Gas Co., Intermountain Gas Company, or Cascade Natural Gas Corporation (collectively the "Utility Group Participating Affiliate") who transfers during the Plan Year and remains employed by a Utility Group Participating Affiliate on the last day of the Plan Year will be eligible to receive a prorated profit sharing contribution from each Utility Group Participating Affiliate noted above which meets its independent profitability targets.

Effective January 1, 2014, it was resolved that Profit Sharing contributions for Eligible Employees of the Utility Group Participating Affiliates would be based upon the Utility Group Participating Affiliates combined profitability targets, and therefore, if the Utility Group Participating Affiliates together attained the required profitability, Eligible Employees of the Utility Group Participating Affiliates would receive a contribution as long as they remained employed by a Utility Group Participating Affiliate on the last day of the Plan Year.

Notwithstanding the foregoing and except as noted herein, effective January 1, 2017, MDU Resources Group, Inc., Montana-Dakota Utilities Co., Intermountain Gas Company, Cascade Natural Gas Corporation, Great Plains Natural Gas Co., WBI Energy, Inc., WBI Energy Midstream, LLC, and WBI Energy Transmission, Inc. (collectively the "Regulated Group Participating Affiliates") will provide a Profit Sharing contribution to Eligible Employees who are classified in salary grade levels 29-38, or a prorated Profit Sharing contribution to Eligible Employees who transfer in or out of salary grade levels 29-38, provided the profitability target is met and they remain employed by a Regulated Group Participating Affiliate as of the last day of the Plan Year. Profit Sharing contributions for Eligible Employees of MDU Resources Group, Inc. will be based on an independent earnings per share target. Profit sharing contributions for Eligible Employees of WBI Energy, Inc., WBI Energy Midstream, LLC, and WBI Energy Transmission, Inc. will be based on a combined profitability target. Employees of the WBI Energy Corrosion Services division of WBI Energy Midstream, LLC are not eligible to receive Profit Sharing contributions. Profit Sharing contributions for Eligible Employees of the Utility Group Participating Affiliates (other than union employees of Montana-Dakota Utilities Co.) will be based on the Utility Group Participating Affiliates combined profitability targets. Profit Sharing contributions for union Eligible Employees of Montana-Dakota Utilities Co., regardless of salary grade level, shall be determined based solely on the profitability of Montana-Dakota Utilities Co.

For purposes of this Supplement, an "Active Employee" means an employee who is still on the payroll, has been temporarily laid off, or who terminated employment due to Disability, death, or after attaining age 60 during such Plan Year, but does not mean an employee whose employment has been terminated effective on or before December 31 of that Plan Year. In addition, for purposes of applying the requirement of completing 1,000 Hours of Service for the Plan Year, such requirement shall not apply to employees terminating after attaining age 60 provided they are not terminated for cause.

Participants who meet the preceding requirements are referred to herein as “Supplement D-1 Participant.”

Explanation: This amendment adds a profit sharing contribution for MDU Resources Group, Inc. based on MDU Resources Group, Inc.’s independent earnings per share target, provides profit sharing to Eligible Employees of WBI Energy, Inc., WBI Energy Midstream, LLC, and WBI Energy Transmission, Inc. only if they remain employed as of the last day of the Plan Year, clarifies that union employees at Montana-Dakota Utilities Co. will have an independent profitability target and that the eligibility of such employees will not be based on salary grade level, clarifies the profitability targets for the regulated entities, and limits eligibility for employees of the regulated entities to employees in salary grade levels 29-38, all effective January 1, 2017.

IN WITNESS WHEREOF, MDU Resources Group, Inc., as Sponsoring Employer of the K-Plan, has caused this amendment to be duly executed by a member of the MDU Resources Group, Inc. Employee Benefits Committee on this 29th day of December, 2016.

MDU RESOURCES GROUP, INC.
EMPLOYEE BENEFITS COMMITTEE

By /s/ Doran N. Schwartz
Doran N. Schwartz, Chairman

MDU RESOURCES GROUP, INC.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
AND COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Years Ended December 31,				
	2016	2015	2014	2013	2012
	(In thousands of dollars)				
Earnings Available for Fixed Charges:					
Net Income (a)	$ 233,102	$ 176,545	$ 185,577	$ 171,236	$ 150,337
Income Taxes	93,132	70,664	64,422	74,235	70,067
	326,234	247,209	249,999	245,471	220,404
Rents (b)	21,656	17,974	15,632	13,240	11,693
Interest (c)	88,045	104,292	94,613	92,255	83,649
Total Earnings Available for Fixed Charges	$ 435,935	$ 369,475	$ 360,244	$ 350,966	$ 315,746
Preferred Dividend Requirements	$ 685	$ 685	$ 685	$ 685	$ 685
Ratio of Income Before Income Taxes to Net Income	140%	140%	135%	143%	147%
Preferred Dividend Factor on Pretax Basis	959	959	925	980	1,007
Fixed Charges (d)	109,636	117,609	111,739	103,910	98,362
Combined Fixed Charges and Preferred Stock Dividends	$ 110,595	$ 118,568	$ 112,664	$ 104,890	$ 99,369
Ratio of Earnings to Fixed Charges	4.0x	3.1x	3.2x	3.4x	3.2x
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	3.9x	3.1x	3.2x	3.3x	3.2x

(a) Net income excludes undistributed income for equity investees.

(b) Represents interest portion of rents estimated at 33 1/3%.

(c) Represents interest, amortization of debt discount and expense on all indebtedness and amortization of interest capitalized, and excludes amortization of gains or losses on reacquired debt (which, under the Federal Energy Regulatory Commission Uniform System of Accounts, is classified as a reduction of, or increase in, interest expense in the Consolidated Statements of Income) and interest capitalized.

(d) Represents rents (as defined above), interest, amortization of debt discount and expense on all indebtedness, and excludes amortization of gains or losses on reacquired debt (which, under the Federal Energy Regulatory Commission Uniform System of Accounts, is classified as a reduction of, or increase in, interest expense in the Consolidated Statements of Income).

MDU RESOURCES GROUP, INC.
List of Subsidiaries
(effective December 31, 2016)

Subsidiaries	Jurisdiction of Formation
1250 Gladding Road, LLC	Delaware
Alaska Basic Industries, Inc.	Alaska
Ames Sand & Gravel, Inc.	North Dakota
Anchorage Sand and Gravel Company, Inc.	Alaska
Baldwin Contracting Company, Inc.	California
BEH Electric Holdings, LLC	Nevada
Bell Electrical Contractors, Inc.	Missouri
BMH Mechanical Holdings, LLC	Nevada
Bombard Electric, LLC	Nevada
Bombard Mechanical, LLC	Nevada
Capital Electric Construction Company, Inc.	Kansas
Capital Electric Line Builders, Inc.	Kansas
Cascade Natural Gas Corporation	Washington
Centennial Energy Holdings, Inc.	Delaware
Centennial Energy Resources International, Inc.	Delaware
Centennial Energy Resources LLC	Delaware
Centennial Holdings Capital LLC	Delaware
Central Oregon Redi-Mix, LLC	Oregon
Concrete, Inc.	California
Connolly-Pacific Co.	California
Continental Line Builders, Inc.	Delaware
Coordinating and Planning Services, Inc.	Delaware
D S S Company	California
Desert Fire Holdings, Inc.	Nevada
Desert Fire Protection, a Nevada Limited Partnership	Nevada
Desert Fire Protection, Inc.	Nevada
Desert Fire Protection, LLC	Nevada
Duro Electric Company	Colorado
E.S.I., Inc.	Ohio
Fairbanks Materials, Inc.	Alaska
Fidelity Exploration & Production Company	Delaware
Fidelity Oil Co.	Delaware
Frebco, Inc.	Ohio
FutureSource Capital Corp.	Delaware
Granite City Ready Mix, Inc.	Minnesota
Hamlin Electric Company	Colorado
Harp Engineering, Inc.	Montana
Hawaiian Cement, a partnership	Hawaii

ILB Hawaii, Inc.	Hawaii
Independent Fire Fabricators, LLC	Nevada
Intermountain Gas Company	Idaho
International Line Builders, Inc.	Delaware
InterSource Insurance Company	Vermont
Jebro Incorporated	Iowa
JTL Group, Inc. (Montana corporation)	Montana
JTL Group, Inc. (Wyoming corporation)	Wyoming
Kent's Oil Service	California
Knife River Corporation	Delaware
Knife River Corporation – North Central	Minnesota
Knife River Corporation – Northwest	Oregon
Knife River Corporation – South	Texas
Knife River Dakota, Inc.	Delaware
Knife River Hawaii, Inc.	Delaware
Knife River Marine, Inc.	Delaware
Knife River Midwest, LLC	Delaware
KRC Holdings, Inc.	Delaware
LME&U Holdings, LLC	Nevada
Lone Mountain Excavation & Utilities, LLC	Nevada
Loy Clark Pipeline Co.	Oregon
LTM, Incorporated	Oregon
MAAK Holdings, Inc.	Nevada
MDU Brasil Ltda.	Brazil
MDU Construction Services Group, Inc.	Delaware
MDU Energy Capital, LLC	Delaware
MDU Holdings, LLC	Delaware
MDU Industrial Services, Inc.	Delaware
MDU Resources International LLC	Delaware
MDU Resources Luxembourg I LLC S.a.r.l.	Luxembourg
MDU Resources Luxembourg II LLC S.a.r.l.	Luxembourg
MDU United Construction Solutions, Inc.	Delaware
Midland Technical Crafts, Inc.	Delaware
Nevada Solar Solutions, LLC	Delaware
Nevada Valley Solar Solutions I, LLC	Delaware
Northstar Materials, Inc.	Minnesota
On Electric Group, Inc.	Oregon
Pouk & Steinle, Inc.	California
Prairie Cascade Energy Holdings, LLC	Delaware
Prairie Intermountain Energy Holdings, LLC	Delaware
Prairielands Energy Marketing, Inc.	Delaware
Rocky Mountain Contractors, Inc.	Montana
USI Industrial Services, Inc.	Delaware
Wagner Group, Inc., The	Delaware

Wagner Industrial Electric, Inc.	Delaware
Wagner-Smith Company, The	Ohio
Wagner-Smith Equipment Co.	Delaware
Wagner-Smith Pumps & Systems, Inc.	Ohio
WBI Canadian Pipeline, Ltd.	Canada
WBI Energy Midstream, LLC	Colorado
WBI Energy Services, Inc.	Delaware
WBI Energy Transmission, Inc.	Delaware
WBI Energy Wind Ridge Pipeline, LLC	Delaware
WBI Energy, Inc.	Delaware
WBI Holdings, Inc.	Delaware
WHC, Ltd.	Hawaii

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-195990 on Form S-3, and No. 333-27877, No. 333-118622, No. 333-114488, and No. 333-212635 on Form S-8, of our reports dated February 24, 2017, relating to the consolidated financial statements and financial statement schedules of MDU Resources Group, Inc. and subsidiaries (the “Company”), and the effectiveness of the Company's internal control over financial reporting, appearing in this Annual Report on Form 10-K of the Company for the year ended December 31, 2016.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 24, 2017

CERTIFICATION

I, David L. Goodin, certify that:

1. I have reviewed this annual report on Form 10-K of MDU Resources Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2017

/s/ David L. Goodin
David L. Goodin
President and Chief Executive Officer

CERTIFICATION

I, Doran N. Schwartz, certify that:

1. I have reviewed this annual report on Form 10-K of MDU Resources Group, Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 24, 2017

/s/ Doran N. Schwartz
Doran N. Schwartz
Vice President and Chief Financial Officer

CERTIFICATION PURSUANT TO 18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906
OF THE SARBANES-OXLEY ACT OF 2002

Each of the undersigned, David L. Goodin, the President and Chief Executive Officer, and Doran N. Schwartz, the Vice President and Chief Financial Officer of MDU Resources Group, Inc. (the "Company"), DOES HEREBY CERTIFY that:

1. The Company's Annual Report on Form 10-K for the year ended December 31, 2016 (the "Report"), fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934; and

2. Information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

IN WITNESS WHEREOF, each of the undersigned has executed this statement this 24 th day of February, 2017 .

/s/ David L. Goodin
David L. Goodin
President and Chief Executive Officer

/s/ Doran N. Schwartz
Doran N. Schwartz
Vice President and Chief Financial Officer

A signed original of this written statement required by Section 906 has been provided to MDU Resources Group, Inc. and will be retained by MDU Resources Group, Inc. and furnished to the Securities and Exchange Commission or its staff upon request.

MDU RESOURCES GROUP, INC.
MINE SAFETY INFORMATION

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Act), as amended by the Mine Improvement and New Emergency Response Act of 2006 (Mine Safety Act). The Dodd-Frank Act requires reporting of the following types of citations or orders:

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

During the twelve months ended December 31, 2016 , none of the Company's operating subsidiaries received citations or orders under the following sections of the Mine Safety Act: 104(b), 110(b)(2), 104(d) and 104(e). During the twelve months ended December 31, 2016, one of the Company's operating subsidiaries received an order under Section 107(a) of the Mine Safety Act. The Company had no mining-related fatalities during this period.

MSHA Identification Number/Contractor ID	Section 104 S&S Citations (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
04-01698	—	—	$ 400	—	—	1
04-05140	—	—	200	—	—	—
04-05459	—	—	314	1	—	2
10-02089	—	—	314	—	—	—
10-02170	2	—	—	—	—	—
21-02614	—	—	114	—	—	—
21-02702	2	—	—	4	4	—
21-02718	3	1	300	—	—	—
21-03086	—	—	114	—	—	—
21-03096	2	—	—	4	4	—
21-03112	—	—	228	—	—	—
21-03127	—	—	217	—	—	—
21-03133	1	—	134	—	—	—
21-03219	—	—	100	—	—	—
21-03348	—	—	100	—	—	—
21-03416	—	—	114	1	1	—
21-03627	—	—	228	—	—	—
21-03642	—	—	114	—	—	—
21-03732	—	—	114	—	—	3
21-03783	—	—	—	1	1	—
21-03870	—	—	114	—	—	—
21-03871	—	—	114	—	—	—
21-03872	1	—	542	1	1	—
24-00459	2	—	724	—	—	—
24-00462	1	—	399	—	—	—
24-00478	—	—	114	—	—	—
24-01935	—	—	114	—	—	—
24-01939	2	—	1,492	—	—	—
24-02022	—	—	328	—	—	—
24-02095	—	—	400	—	—	—
24-02414	—	—	100	—	—	—
32-00776	—	—	100	—	—	—
32-00777	—	—	228	—	—	—
32-00778	—	—	100	—	—	—
32-00950	—	—	—	—	1	1
32-00966	—	—	—	—	—	9
35-00426	—	—	114	—	—	—
35-00495	—	—	114	1	1	—
35-00512	1	—	100	—	—	—
35-00521	—	—	200	—	—	—
35-00555	1	—	392	—	—	—
35-02968	—	—	100	—	—	—

MSHA Identification Number/Contractor ID	Section 104 S&S Citations (#)	Section 107(a) Orders (#)	Total Dollar Value of MSHA Assessments Proposed ($)	Legal Actions Pending as of Last Day of Period (#)	Legal Actions Initiated During Period (#)	Legal Actions Resolved During Period (#)
35-03022	1	—	457	—	—	—
35-03131	—	—	200	—	—	—
35-03321	—	—	373	—	—	—
35-03404	—	—	100	—	—	—
35-03496	1	—	656	—	—	—
35-03505	—	—	100	—	—	—
35-03527	—	—	428	—	—	—
35-03581	—	—	228	—	—	—
35-03594	—	—	390	—	—	—
35-03595	—	—	100	—	—	—
35-03605	—	—	542	—	—	—
35-03667	—	—	100	—	—	—
35-03751	—	—	342	—	—	—
35-03752	—	—	100	—	—	—
41-02639	—	—	600	—	—	2
41-03931	—	—	248	—	—	—
48-00715	—	—	100	—	—	—
48-01383	1	—	607	—	—	—
50-00883	2	—	1,364	—	—	—
50-01196	5	—	1,867	—	—	—
51-00036	5	—	5,585	—	—	4
51-00192	—	—	100	—	—	—
51-00195	—	—	100	—	1	1
	33	1	$ 23,681	13	14	23

Legal actions pending before the Federal Mine Safety and Health Review Commission (the Commission) may involve, among other questions, challenges by operators to citations, orders and penalties they have received from the Federal Mine Safety and Health Administration (MSHA) or complaints of discrimination by miners under section 105 of the Mine Act. The following is a brief description of the types of legal actions that may be brought before the Commission.

- Contests of Citations and Orders - A contest proceeding may be filed with the Commission by operators, miners or miners' representatives to challenge the issuance of a citation or order issued by MSHA.
- Contests of Proposed Penalties (Petitions for Assessment of Penalties) - A contest of a proposed penalty is an administrative proceeding before the Commission challenging a civil penalty that MSHA has proposed for the alleged violation contained in a citation or order.
- Complaints for Compensation - A complaint for compensation may be filed with the Commission by miners entitled to compensation when a mine is closed by certain withdrawal orders issued by MSHA. The purpose of the proceeding is to determine the amount of compensation, if any, due miners idled by the orders.
- Complaints of Discharge, Discrimination or Interference - A discrimination proceeding is a case that involves a miner's allegation that he or she has suffered a wrong by the operator because he or she engaged in some type of activity protected under the Mine Act, such as making a safety complaint.
- Applications for Temporary Relief - Applications for temporary relief from any modification or termination of any order or from any order issued under section 104 of the Mine Act.
- Appeals of Judges' Decisions or Orders to the Commission - A filing with the Commission for discretionary review of a judge's decision or order by a person who has been adversely affected or aggrieved by such decision or order.

The following table reflects the types of legal actions pending before the Commission as of December 31, 2016 :

MSHA Identification Number	Contests of Citations and Orders	Contests of Proposed Penalties	Complaints for Compensation	Complaints of Discharge, Discrimination or Interference	Applications for Temporary Relief	Appeals of Judges' Decisions or Orders to the Commission
04-05459	—	—	—	—	—	1
21-02702	4	—	—	—	—	—
21-03096	4	—	—	—	—	—
21-03416	1	—	—	—	—	—
21-03783	1	—	—	—	—	—
21-03872	1	—	—	—	—	—
35-00495	1	—	—	—	—	—
	12	—	—	—	—	1