Section 1: 10-K (MDU RESOURCES 2017 FORM 10-K)

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, 2017

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 1-03480

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: None

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, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth 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 ☐
	Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

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, 2017: $5,116,974,651.

Indicate the number of shares outstanding of the registrant's common stock, as of February 15, 2018: 195,304,376 shares.

DOCUMENTS INCORPORATED BY REFERENCE
Relevant portions of the registrant's 2018 Proxy Statement, to be filed no later than 120 days from December 31, 2017, 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
Andeavor Field Services LLC	Formerly QEP Field Services, LLC doing business as Tesoro Logistics Rockies LLC
Army Corps	U.S. Army Corps of Engineers
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
Bcf	Billion cubic feet
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
Btu	British thermal unit
Calumet	Calumet Specialty Products Partners, L.P.
Capital Electric	Capital Electric Construction Company, Inc., a direct wholly owned subsidiary of MDU Construction Services
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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
ICWU	International Chemical Workers Union
IFRS	International Financial Reporting Standards

Definitions

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
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.
MMBtu	Million Btu
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
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
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's 50 percent ownership interests were sold effective January 1, 2017)
Proxy Statement	Company's 2018 Proxy Statement
PRP	Potentially Responsible Party
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
SSIP	System Safety and Integrity Program
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company 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 Supreme Court	Supreme Court of the United States
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., a direct 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

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 - Business Segment Financial and Operating Data.

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.

The Company operates with a two-platform business model. Its regulated energy delivery platform and its construction materials and services platform are each comprised of different operating segments. Some of these segments experience seasonality related to the industries in which they operate. The two-platform approach helps balance this seasonality and the risk associated with each type of industry. Through its regulated energy delivery platform, the Company provides electric and natural gas services to customers, generates, transmits and distributes electricity, and provides natural gas transportation, storage and gathering services. These businesses are regulated by state public service commissions and/or the FERC. The construction materials and services platform provides construction services to a variety of industries, including commercial, industrial and governmental, and provides construction materials through aggregate mining and marketing of related products, such as ready-mix concrete and asphalt.

The Company is organized into five reportable business segments. These business segments include: electric, natural gas distribution, pipeline and midstream, construction materials and contracting, and construction services. The Company's reportable segments are determined 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 segments is defined based on the reporting and review process used by the Company's chief executive officer.

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 the pipeline and midstream segment, 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.

On November 21, 2017, the Company announced that its board of directors has directed senior management to explore reorganization to a holding company structure. The purpose of a potential reorganization would be to make Montana-Dakota and Great Plains, which today are divisions of the Company, into a subsidiary of the holding company, just as the Company's other operating companies are wholly owned subsidiaries.

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

As of December 31, 2017, the Company had 10,140 employees with 205 employed at MDU Resources Group, Inc., 963 at Montana-Dakota, 35 at Great Plains, 348 at Cascade, 240 at Intermountain, 319 at WBI Holdings, 3,466 at Knife River and 4,564 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, 2017.

At Montana-Dakota and WBI Energy Transmission, 353 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, 192 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 685 of its construction materials and contracting employees. Knife River is in negotiations on one of its labor contracts.

MDU Construction Services has 130 labor contracts representing the majority of its employees. MDU Construction Services is in negotiations on 10 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 142,901 residential, commercial, industrial and municipal customers in 178 communities and adjacent rural areas as of December 31, 2017. For more information on the retail customer classes served, see the table below. The principal properties owned by Montana-Dakota for use in its electric operations include interests in 16 electric generating units at 11 facilities and three small portable diesel generators, as further described under System Supply, System Demand and Competition, approximately 3,200 and 4,900 miles of transmission and distribution lines, respectively, and 73 transmission and 296 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, 2017, Montana-Dakota's net electric plant investment was $1.4 billion, and rate base was $1.1 billion.

The retail customers served and respective revenues by class for the electric business were as follows:

	2017			2016			2015		
	Customers Served		**Revenues**	Customers Served		Revenues	Customers Served		Revenues
				(Dollars in thousands)					
Residential	**118,379**	**$**	**121,171**	118,483	$	117,014	118,413	$	107,767
Commercial	**22,764**		**140,856**	22,693		135,390	22,423		121,463
Industrial	**242**		**34,417**	244		31,913	240		32,786
Other	**1,516**		**8,275**	1,528		7,580	1,511		6,791
	142,901	**$**	**304,719**	142,948	$	291,897	142,587	$	268,807

Other electric revenues for Montana-Dakota were $38.1 million, $30.4 million and $11.8 million for the years ended December 31, 2017, 2016 and 2015, respectively.

The percentage of electric retail revenues by jurisdiction was as follows:

	2017	2016	2015
North Dakota	**66%**	68%	65%
Montana	**20%**	19%	21%
Wyoming	**9%**	8%	9%
South Dakota	**5%**	5%	5%

Retail electric rates, service, accounting and certain security issuances are subject to regulation by the MTPSC, NDPSC, 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 interconnected system consists of 15 electric generating units at 10 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 528.2 in 2017. ZRCs are a MW of demand equivalent measure and are allocated to individual generators to meet planning reserve margin requirements within MISO. For 2017, Montana-Dakota's total ZRCs, including its firm purchase power contracts, were 553.1. Montana-Dakota's planning reserve margin requirement within MISO was 530.2 for 2017. 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 2022 will approximate two percent annually. Montana-Dakota's interconnected system electric generating capability includes five steam-turbine generating units at four facilities using coal for fuel, four combustion turbine units at three facilities, 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 construction on 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. All necessary easements have been secured and the project is expected to be completed in 2019.

In December 2016, Montana-Dakota signed a 25-year agreement to purchase power from the expansion of the Thunder Spirit Wind farm in southwest North Dakota. In November 2017, the NDPSC approved the advance determination of prudence for the purchase of the Thunder Spirit Wind farm expansion. Montana-Dakota expects to soon have a purchase agreement in place and finalize the purchase when the construction is complete in late 2018. With the addition of the expansion, Montana-Dakota's total wind farm generation capacity will be approximately 155 MW and increase Montana-Dakota's electric generation portfolio to approximately 27 percent renewables. The original 107.5-MW wind farm includes 43 turbines; it was purchased by Montana-Dakota in December 2015. The expansion will include 16 turbines. Acquisition costs for the project are estimated to be approximately $85 million.

Additional energy will be purchased as needed, or if more economical, from the MISO market. In 2017, Montana-Dakota purchased approximately 26 percent of its net kWh needs for its interconnected system through the MISO market.

Approximately 24 percent of the electricity delivered to customers from Montana-Dakota's owned generation in 2017 was from renewable resources. Although Montana-Dakota's generation resource capacity has increased to serve the needs of customers, the carbon dioxide emission intensity of the electric generation resource fleet has been reduced by more than 25 percent since 2003 and is expected to continue to decline.

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)	2017 ZRCs (a)	2017 Net Generation (kWh in thousands)
Interconnected System:				
North Dakota:				
Coyote (b)	Steam	103,647	83.4	652,071
Heskett	Steam	86,000	87.1	454,134
Heskett	Combustion Turbine	89,038	59.0	3,400
Glen Ullin	Heat Recovery	7,500	4.0	45,548
Cedar Hills	Wind	19,500	5.0	59,385
Diesel Units	Oil	5,475	3.7	9
Thunder Spirit	Wind	107,500	20.6	428,528
South Dakota:				
Big Stone (b)	Steam	94,111	101.8	469,709
Montana:				
Lewis & Clark	Steam	44,000	50.9	225,984
Lewis & Clark	Reciprocating Internal Combustion Engine	18,700	16.1	5,453
Glendive	Combustion Turbine	75,522	68.8	2,333
Miles City	Combustion Turbine	23,150	21.5	406
Diamond Willow	Wind	30,000	6.3	93,696
		704,143	528.2	2,440,656
Sheridan System:				
Wyoming:				
Wygen III (b)	Steam	28,000	N/A	189,984
		732,143	528.2	2,630,640

(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 2020, 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 250,000 tons in 2018 and 2019 from Contura Coal Sales, LLC and 550,000 tons in 2018 from Peabody COALSALES, LLC both 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,	**2017**	2016	2015
Average cost of coal per MMBtu	**$ 2.07**	$ 1.89	$ 1.75
Average cost of coal per ton	**$ 30.04**	$ 27.45	$ 25.41

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 2024. 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.

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 electric fuel and purchased power costs (including demand charges) and Montana-Dakota 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 electric 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 electric fuel and purchased power costs. 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. Montana-Dakota's results of operations reflect 95 percent of the increases or decreases from the base purchased power costs and in addition also reflects 85 percent of the increases or decreases from the base coal price, which is also recovered through the Electric Power Supply Cost Adjustment. For more information, see Item 8 - Note 4.

For the Thunder Spirit Wind project, Montana-Dakota implemented a renewable resource cost adjustment rider, and all of Montana-Dakota's wind resources pertaining to North Dakota electric operations were placed in this rider upon a final order of the most recent North Dakota electric general rate case. 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.

In Montana, Montana-Dakota recovers in rates through a tracking mechanism the increases associated with its allocated share of Montana state and local taxes assessed to electric operations on an after tax basis.

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, and a final permit was issued in May 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, and a final permit was issued in July 2017. The Title V Operating Permit renewal application for Coyote Station was submitted timely to the North Dakota Department of Health in September 2017, with the permit expected to be issued in 2018. 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 2018.

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

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

Montana-Dakota incurred $3.7 million of environmental capital expenditures in 2017, mainly for coal ash management projects at Lewis & Clark Station, Big Stone Station and Coyote Station. Environmental capital expenditures are estimated to be $9.6 million, $9.2 million and $1.5 million in 2018, 2019 and 2020, 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, including a future regulation that may replace the Clean Power Plan rule published by the EPA in October 2015. The Clean Power Plan requires existing fossil fuel-fired electric generating facilities to reduce carbon dioxide emissions. 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. The EPA filed a motion with the D.C. Circuit Court on March 28, 2017, requesting the Clean Power Plan's case be held in abeyance. The D.C. Circuit Court granted the EPA's motion to hold the case in abeyance for 60 days. On August 8, 2017, the D.C. Circuit Court issued an order holding the case in abeyance for an additional 60-day period and directed the EPA to file status reports at 30-day intervals. In parallel, the EPA published a proposal on October 16, 2017, to repeal the Clean Power Plan in its entirety and followed with an advance notice of proposed rulemaking published in the Federal Register on December 28, 2017, requesting comment on replacing the Clean Power Plan through new rulemaking.

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 938,867 residential, commercial and industrial customers in 335 communities and adjacent rural areas across eight states as of December 31, 2017, and provide natural gas transportation services to certain customers on the Company's systems. For more information on the retail customer classes served, see the table below. These services are provided through distribution systems aggregating approximately 19,600 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, 2017, the natural gas distribution operations' net natural gas distribution plant investment was $1.5 billion, and rate base was $975 million.

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

	2017		2016		2015	
	Customers Served	**Revenues**	Customers Served	Revenues	Customers Served	Revenues
			(Dollars in thousands)			
Residential	**833,255**	**$ 477,699**	818,163	$ 429,828	803,846	$ 455,301
Commercial	**104,795**	**283,899**	103,438	253,333	101,688	277,022
Industrial	**817**	**24,030**	807	23,337	811	26,568
	938,867	**$ 785,628**	922,408	$ 706,498	906,345	$ 758,891

Transportation and other revenues for the natural gas distribution operations were $62.8 million, $59.6 million and $58.5 million for the years ended December 31, 2017, 2016 and 2015, respectively.

The percentage of the natural gas distribution operations' retail sales revenues by jurisdiction was as follows:

	2017	2016	2015
Idaho	**33%**	34%	32%
Washington	**26%**	26%	26%
North Dakota	**13%**	13%	15%
Montana	**9%**	8%	8%
Oregon	**8%**	8%	8%
South Dakota	**6%**	6%	6%
Minnesota	**3%**	3%	3%
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, South Dakota Intrastate Pipeline, TransCanada Corporation, 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.

In Montana, Montana-Dakota recovers in rates through a tracking mechanism the increases associated with Montana state and local taxes assessed to natural gas operations on an after tax basis.

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 it is 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 2017. 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 2020.

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 may seek recovery in its natural gas rates charged to customers for certain 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 natural gas 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, 2017, its net plant investment was $404.6 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 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.

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, commercial and industrial 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 2017 represented 34 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 for existing customers in the fields in which it operates. Its focus on customer service and the variety of services it offers 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 2017 and do not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2020.

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. These products are used in most types of construction, performed by Knife River and other companies, including roads, freeways and bridges, as well as homes, schools, shopping centers, office buildings and industrial parks. Knife River focuses on vertical integration of construction services to support the aggregate based product lines including aggregate placement, asphalt and concrete paving, and site development and grading. 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.

Knife River's backlog was approximately $486 million, $538 million and $491 million at December 31, 2017, 2016 and 2015, respectively. The decrease in backlog at December 31, 2017, compared to backlog at December 31, 2016, was primarily attributable to a lower backlog of state agency work. Backlog increases with awards of new contracts and decreases as work is performed on existing contracts. Knife River expects to complete a significant amount of the backlog at December 31, 2017, during the next 12 months.

Knife River's backlog is comprised of the anticipated revenues from the uncompleted portion of services to be performed under job-specific contracts. A project is included in backlog when a contract is awarded and agreement on contract terms has been reached. However, backlog does not contain contracts for time and material projects that a fixed amount cannot be determined. Backlog is comprised of: (a) original contract amounts, (b) change orders for which customers have approved and (c) claim amounts that have been made against customers for which are determined to have a legal basis under existing contractual arrangements and as to which recovery is considered to be probable. Such claim amounts were immaterial for all periods presented. Backlog may be subject to delay, default or cancellation at the election of the customers. Historically, cancellations have not had a materially adverse effect on backlog. Due to the nature of its contractual arrangements, in many instances Knife River's customers are not committed to the specific volumes of services to be purchased under a contract, but rather Knife River 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.

Competition Knife River's construction materials products and contracting services are marketed under highly competitive conditions. Price is the principal competitive force to which these products and services are subject, with service, quality, delivery time and proximity to the customer also being significant factors. Knife River focuses on markets located near aggregate sites to reduce transportation costs which allows Knife River to remain competitive with the pricing of aggregate products. 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 and contracting services is significantly influenced by the cyclical nature of the construction industry in general. In addition, construction materials and contracting services 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 on roads and infrastructure projects, general economic conditions within the market area that influence both the commercial and residential sectors, and prevailing interest rates.

Knife River's customers are a diverse group which includes federal, state and municipal government agencies, commercial and residential developers, and private parties. The mix of sales by customer will vary each year depending on the work available. 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.

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 891 million tons of the 965 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 2015 through 2017. 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, 2017, and sales for the years ended December 31, 2017, 2016 and 2015:

	Number of Sites (Crushed Stone)		Number of Sites (Sand & Gravel)		Tons Sold (000's)			Estimated Reserves (000's tons)	Lease Expiration	Reserve Life (years)
Production Area	owned	leased	owned	leased	**2017**	2016	2015			
Anchorage, AK	—	—	1	—	**1,425**	1,343	1,837	14,548	N/A	9
Hawaii	—	5	—	—	**1,614**	1,901	1,892	50,659	2018-2064	28
Northern CA	—	—	9	1	**1,785**	1,604	1,580	43,812	2018	26
Southern CA	—	2	—	—	**55**	224	118	91,567	2035	Over 100
Portland, OR	1	3	5	3	**4,694**	4,044	3,562	213,018	2025-2057	52
Eugene, OR	3	4	6	—	**633**	662	819	153,975	2021-2049	Over 100
Central OR/WA/ID	—	1	5	2	**2,160**	1,685	1,493	86,307	2020-2087	49
Southwest OR	5	5	10	6	**2,367**	2,689	1,872	100,875	2019-2053	44
Central MT	—	—	3	2	**1,065**	1,135	1,383	28,294	2023-2027	24
Northwest MT	—	—	8	1	**1,745**	1,514	1,423	64,451	2020	41
Wyoming	—	—	1	2	**613**	742	888	10,092	2019-2020	13
Central MN	—	1	33	8	**2,773**	2,831	2,556	50,092	2018-2028	18
Northern MN	2	—	14	2	**270**	537	595	23,248	2018-2021	50
ND/SD	—	—	2	17	**1,100**	1,643	1,959	24,389	2019-2028	16
Texas	1	2	1	—	**1,192**	1,243	1,138	9,709	2022-2029	8
Sales from other sources					**4,722**	3,783	3,844			
					28,213	27,580	26,959	965,036		

The 965 million tons of estimated aggregate reserves at December 31, 2017, are comprised of 457 million tons that are owned and 508 million tons that are leased. Approximately 45 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 23 years, including options for renewal that are at Knife River's discretion. Based on a three-year average of sales from 2015 through 2017 of leased reserves, the average time necessary to produce remaining aggregate reserves from such leases is approximately 47 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:

	2017	2016	2015
		(000's of tons)	
Aggregate reserves:			
Beginning of year	**989,084**	1,022,513	1,061,156
Acquisitions	**2,726**	24,993	7,406
Sales volumes*	**(23,491)**	(23,797)	(23,115)
Other**	**(3,283)**	(34,625)	(22,934)
End of year	**965,036**	989,084	1,022,513

* 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 the Clean Air Act and the 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 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 2017 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 2020.

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 inside and outside specialty contracting services. Its outside services include design, construction and maintenance of overhead and underground electrical distribution and transmission lines, substations, external lighting, traffic signalization, and gas pipelines, as well as utility excavation and the manufacture and distribution of transmission line construction equipment. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. This business also designs, constructs and maintains renewable energy projects.

These specialty contracting 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, 2017, MDU Construction Services owned or leased facilities in 17 states. This space is used for offices, equipment yards, manufacturing, warehousing, storage and vehicle shops.

MDU Construction Services’ backlog at December 31 was as follows:

	2017	2016	2015
		(In millions)	
Inside specialty contracting	$ 625	$ 435	$ 408
Outside specialty contracting	83	40	85
	$ 708	$ 475	$ 493

The increase in backlog at December 31, 2017, compared to backlog at December 31, 2016, was primarily attributable to an increase in projects from all revenue streams based on customer demand. Backlog increases with awards of new contracts and decreases as work is performed on existing contracts. MDU Construction Services expects to complete a significant amount of the backlog at December 31, 2017, during the next 12 months.

MDU Construction Services’ backlog is comprised of the anticipated revenues from the uncompleted portion of services to be performed under job-specific contracts. A project is included in backlog when a contract is awarded and agreement on contract terms has been reached. However, backlog does not contain contracts for time and material projects that a fixed amount cannot be determined. Backlog is comprised of: (a) original contract amounts, (b) change orders for which customers have approved, (c) pending change orders expected to receive confirmation in the ordinary course of business and (d) claim amounts that have been made against customers for which are determined to have a legal basis under existing contractual arrangements and as to which recovery is considered to be probable. Such claim amounts were immaterial for all periods presented. Backlog may be subject to delay, default or cancellation at the election of the customers. Historically, cancellations have not had a material adverse effect on backlog. 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 2017 and does not expect to incur any material capital expenditures related to environmental compliance with current laws and regulations through 2020.

For information regarding construction services litigation, see Item 8 - Note 17.

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. If any of the risks described below actually occur, the Company's business, prospects, financial condition or financial results could be materially harmed.

Economic Risks

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's electric and natural gas transmission and distribution businesses are subject to comprehensive regulation 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, income taxes, property and other taxes, franchises; recovery of purchased power and purchased natural gas costs; and siting of generation and transmission facilities. 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.

There can be no assurance that applicable regulatory commissions will determine all the costs of the Company's electric and natural gas transmission and distribution businesses to have been prudent, which could result in disallowance of costs. Also, the regulatory process for approval of rates for these businesses may not result in full recovery of the costs of providing services. Changes in regulatory requirements or operating conditions may require early retirement of certain assets. While regulation typically provides relief for these types of retirements, there is no assurance the regulators will allow full recovery of all remaining costs leaving stranded asset costs. Rising fuel costs could increase the risk that the utility businesses will not be able to fully recover those fuel costs from their customers.

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, which may defer potential acquirers from approaching the Company or impact the Company's ability to pursue otherwise attractive acquisitions.

Economic volatility affects the Company's operations, as well as the demand for its products and services.

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 affect the funding available for infrastructure spending.

The ability of the Company's electric and natural gas distribution businesses to grow in service territory, customer base and usage demand is affected by the economic environments and population growth 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. Further, any material decreases in energy demand by customers, for economic or other reasons, could have a material adverse impact on the Company's earnings and results of operations.

The Company's operations involve risks that may result from catastrophic events.

The Company's operations include a variety of inherent hazards and operating risks, such as product leaks, explosions, mechanical failures, vandalism, acts of terrorism and acts of war, which could result in loss of human life; personal injury; property damage; environmental pollution; impairment of operations; and substantial financial 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.

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's operations, particularly its electric and natural gas transmission and distribution businesses, require significant capital investment. The Company relies on the issuance of long-term debt and equity securities 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 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

The issuance of a substantial amount of the Company's common stock, whether issued in connection with an acquisition or otherwise, could have a dilutive effect on existing shareholders, or the perception that such an issuance could occur, may adversely affect the market price of the Company's common stock.

The regulatory approval, permitting, construction, startup and/or operation of pipelines and power generation and transmission facilities may involve unanticipated events, delays and unrecoverable costs.

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.

Additionally, operating or other costs 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.

Financial market changes could impact the Company's pension and post-retirement benefit plans and obligations.

The global demand and price volatility for natural resources, interest rate changes, governmental budget constraints and threat of terrorism can create volatility in the financial markets. Changing financial market conditions could negatively affect the 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 for those plans as well liabilities and funding requirements for multiemployer plans to which the Company is a participating employer.

The backlogs at the Company's construction materials and contracting and construction services businesses may not accurately represent future revenue.

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. The timing of contract awards, duration of large new contracts and the mix of services can significantly affect backlog. Backlog at any given point in time may not accurately represent the revenue or net income that is realized in any period and the backlog as of the end of the year may not be indicative of the revenue and net income expected to be earned in the following year and should not be relied upon as a stand-alone indicator of future revenues or net income.

The Company's pipeline and midstream business is dependent on factors, including commodity prices and commodity price basis differentials, that are subject to external influences.

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 external factors impact the development of natural gas supplies and the expansion and operation of natural gas pipeline systems. Prolonged depressed prices for oil, NGL and natural gas could negatively affect the growth, results of operations, cash flows and asset values of the Company's pipeline and midstream business.

Reductions in the Company's credit ratings could increase financing costs.

There is no assurance that the Company's current credit ratings, or those of its subsidiaries, will remain in effect or that a rating will not be lowered or withdrawn by a rating agency. The Company's credit ratings may also change as a result of the differing methodologies or changes in the methodologies used by the rating agencies. A downgrade in credit ratings could lead to higher borrowing costs. A credit rating is not a recommendation to buy, sell or hold securities and is applicable only to the specific security to which it applies. Investors should make their own evaluation as to whether an investment in the security is appropriate.

Increasing costs associated with health care plans may adversely affect the Company's results of operations.

The Company's self-insured costs of health care benefits for eligible employees continues to increase. Increasing levels of large individual health care claims and overall health care claims could have an adverse impact on operating results, financial position and liquidity. Legislation related to health care could also change the Company's benefit program and costs.

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

If the Company's customers or counterparties experience financial difficulties, the Company could experience difficulty in collecting receivables. The nonpayment and/or nonperformance by the Company's customers and counterparties, particularly customers and counterparties of the Company’s construction materials and contracting and construction services businesses for large construction projects, could have a negative impact on the Company's results of operations and cash flows. The Company may also have indirect credit risk due to participation in energy markets such as MISO in which credit losses are socialized to all participants.

Changes in tax law may negatively affect the Company's business.

On December 22, 2017, President Trump signed into law the TCJA that significantly reforms the Internal Revenue Code of 1986, as amended. The TCJA, among other things, includes reductions to United States federal tax rates, repeals the domestic production deduction, disallows regulated utility property for immediate expensing, and modifies or repeals many other business deductions and credits. The changes to the Internal Revenue Code could materially impact the Company. Future guidance, regulations and interpretations clarifying items within the TCJA may be contrary to the Company’s current interpretation or regulatory actions and could have an adverse impact to the Company. The Company continues to examine the impact the TCJA may have on the Company in future periods. The TCJA's impact on the economy, including overall demand and competition for the products and services the Company provides and associated labor availability and costs, is unknown and there could be negative impacts to the Company. The Company's utility businesses' cash flows may be negatively impacted by the disallowance of immediate expensing of utility property. Other changes to federal and state tax laws have the ability to benefit or adversely affect the Company's earnings and customer costs. Significant changes to corporate tax rates could result in the impairment of deferred tax assets that are established based on existing law at the time of deferral. Changes to the value of various tax credits could change the economics of resources and the resource selection for the electric generation business. Regulation incorporates changes in tax law into the rate setting process for the regulated energy delivery businesses and therefore could create timing delays before the impact of changes are realized.

Environmental and Regulatory Risks

The Company's operations could be adversely impacted by climate change.

Climate change may create physical and financial risks to the Company. Such risks could have an adverse effect on the Company's financial condition, results of operations and cash flows.

Utility customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent the largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease. Increased energy use by its utility customers due to weather changes may require the Company to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may result in decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of the Company's service territory could also have an impact on revenues. The Company buys and sells electricity that might be generated outside its service territory depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand may raise electricity prices, which would increase the cost of energy provided to customers.

Severe weather impacts the Company's utility service territories, primarily when thunderstorms, tornadoes and snow or ice storms occur. Severe weather events may damage or disrupt the Company's electric and natural gas transmission and distribution facilities, which could increase costs to repair damaged facilities and restore service to customers. The cost of providing service could increase to the extent the frequency of extreme weather events increases because of climate change or otherwise. The Company may not recover all costs related to mitigating these physical risks.

Severe weather may result in disruptions to the pipeline and midstream business's natural gas supply and transportation systems. These changes could result in increased maintenance and capital costs, disruption of service, regulatory actions and lower customer satisfaction.

Extreme weather conditions caused by climate change or otherwise may cause infrastructure construction projects to be delayed or canceled and limit resources available for such projects increasing the project costs at the construction materials and contracting and construction services businesses.

Climate change may impact a region's economic health, which could impact revenues at all of the Company's businesses. The Company's financial performance is tied to the health of the regional economies served. The Company provides natural gas and electric utility service, as well as construction materials and services, for states and communities that are economically affected by the agriculture industry. Increases in severe weather events or significant changes in temperature and precipitation patterns could adversely affect the agriculture industry and correspondingly the economies of the states and communities affected by that industry.

The price of energy also has an impact on the economic health of communities. The cost of additional regulatory requirements to combat climate change, such as regulation of carbon dioxide emissions under the Clean Air Act, or other environmental regulation could impact the availability of goods and prices charged by suppliers which would normally be borne by consumers through higher prices for energy and purchased goods. To the extent financial markets view climate change and emissions of GHGs as a financial risk, this could negatively affect the Company's ability to access capital markets or cause less than ideal terms and conditions.

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, 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. Site and groundwater analyses as required by the rule may identify the need to upgrade or close 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 76 percent of the electricity it generated in 2017 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. The EPA filed a motion with the D.C. Circuit Court on March 28, 2017, requesting the Clean Power Plan's case be held in abeyance. The D.C. Circuit Court granted the EPA’s motion to hold the case in abeyance for 60 days. On August 8, 2017, the D.C. Circuit Court issued an order holding the case in abeyance for an additional 60-day period and directed the EPA to file status reports at 30-day intervals. In parallel, the EPA published a proposal on October 16, 2017, to repeal the Clean Power Plan in its entirety and followed with an advance notice of proposed rulemaking published in the Federal Register on December 28, 2017, requesting comment on replacing the Clean Power Plan through new rulemaking. Compliance costs will become clearer as the EPA completes new rulemaking.

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 currently complying with the rules impacting new and modified sources. 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 oil and gas facility operators, including WBI Energy, to begin the process of existing source rule development. On March 7, 2017, the EPA published notice of withdrawal of the Information Collection Request.

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 asserted that the Washington DOE undertook this rulemaking without the requisite statutory authority. On December 15, 2017, the Thurston County Superior Court vacated the Clean Air rule holding that it is invalid due to a lack of legislative approval to adopt the rule. The ruling may still be appealed by the Washington DOE or interveners. Litigation in the United States District Court for the Eastern District of Washington remains in abeyance pending evaluation of the recent 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.

Other Risks

The Company's various businesses are seasonal and subject to weather conditions that 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 and affect the price of energy commodities. Utility operations have historically generated lower revenues when weather conditions are cooler than normal in the summer and warmer than normal in the winter particularly in jurisdictions that do not have decoupling mechanisms in place. Where decoupling mechanism are in place, there is no assurance the Company will continue to receive such regulatory protection from adverse weather in future rates.

Adverse weather conditions, such as heavy or sustained rainfall or snowfall, storms, wind, and colder weather may affect the demand for products and the ability to perform services at the construction businesses and affect ongoing operation and maintenance and construction activities for the electric and natural gas transmission and distribution businesses. 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.

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 experience 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 for gathering, transportation and storage business. Competition could negatively affect the Company's results of operations, financial position and cash flows.

The Company's inability to obtain, develop and retain key personnel and skilled labor forces may have a negative effect on the Company's operations.

The Company must attract, develop and retain executive officers and other professional, technical and skilled labor forces with the skills and experience necessary to successfully manage, operate and grow the Company's businesses. Competition for these employees is high, and in some cases competition for these employees is on a regional or national basis. A shortage in the supply of these skilled personnel creates competitive hiring markets and increased labor expenses, decreased productivity and potentially lost business opportunities. Additionally, if the Company is unable to hire employees with the requisite skills, the Company may also be forced to incur significant training expenses. As a result, the Company's ability to maintain productivity, relationships with customers, competitive costs, and quality services is limited by the ability to employ the necessary skilled personnel and could negatively affect the Company's results of operations, financial position and cash flows.

The Company's construction materials and contracting and construction services businesses may be exposed to warranty claims.

The Company, particularly its construction businesses, may provide warranties guaranteeing the work performed against defects in workmanship and material. If warranty claims occur, they may require the Company to re-perform the services or to repair or replace the warranted item, at a cost to the Company, and could also result in other damages if the Company is not able to adequately satisfy warranty obligations. In addition, the Company may be required under contractual arrangements with customers to warrant any defects or failures in materials the Company purchased from third parties. While the Company generally requires suppliers to provide warranties that are consistent with those the Company provides to customers, if any of the suppliers default on their warranty obligations to the Company, the Company may nonetheless incur costs to repair or replace the defective materials. Costs incurred as a result of warranty claims could adversely affect the Company's results of operations, financial condition and cash flows.

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

The Company depends on earnings from its divisions and dividends from its subsidiaries to pay dividends on its common stock. Regulatory, contractual and legal limitations, as well as capital requirements and the Company's financial performance or cash flows, could restrict or influence the Company's ability or decision 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 participation 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.

Information technology disruptions or cyberattacks could adversely impact the Company's operations.

The Company's operations require uninterrupted operation of information technology systems and network infrastructure. While the Company has policies, procedures and processes in place designed to strengthen and protect these systems, they may be vulnerable to failures or unauthorized access due to hacking, theft, sabotage, malicious software, acts of terrorism, acts of war, acts of nature or other causes. If these systems fail or become comprised, and they are not recovered in a timely manner, the Company may be unable to fulfill critical business functions. This may include interruption of electric generation, transmission and distribution facilities, natural gas storage and pipeline facilities, and facilities for delivery of construction materials or other products and services. The Company’s accounting systems and its ability to collect information and invoice customers for products and services could also be disrupted. If the Company’s operations were disrupted, it could result in decreased revenues or significant remediation costs that have a material adverse effect on the Company's results of operations and cash flows. Additionally, because electric generation and transmission systems and natural gas pipelines are part of interconnected systems with other operators’ facilities, a cyber-related disruption in another operator’s system could negatively impact the Company's business.

The Company, through the ordinary course of business, requires access to sensitive customer, employee and Company data. While the Company has implemented extensive security measures, a breach of its systems could compromise sensitive data. Such an event could result in negative publicity and reputational harm, remediation costs, legal claims and fines that could have an adverse effect on the Company's financial results. Third-party service providers that perform critical business functions for the Company or have access to sensitive information within the Company also may be vulnerable to security breaches and information technology 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 risks to the Company. These other factors may materially negatively 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 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
- 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
- Losses or costs relating to litigation
- The ability to effectively integrate the operations and the internal controls of acquired companies

Item 1B. Unresolved Staff Comments

The Company has no unresolved comments with the SEC.

Item 3. Legal Proceedings

For information regarding legal proceedings required by this item, 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 New York Stock Exchange during 2017 and 2016 and dividends declared thereon were as follows:

	Common Stock Price (High)	Common Stock Price (Low)	Common Stock Dividends Declared Per Share
2017			
First quarter	**$29.74**	**$25.83**	**$.1925**
Second quarter	**27.89**	**25.58**	**.1925**
Third quarter	**27.73**	**25.14**	**.1925**
Fourth quarter	**28.22**	**25.89**	**.1975**
			$.7750
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

As of December 31, 2017, the Company's common stock was held by approximately 11,703 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, 2017	—	—	—	—
November 1 through November 30, 2017	38,121	$26.88	—	—
December 1 through December 31, 2017	2,451	$27.70	—	—
Total	40,572		—	—

(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

	2017	2016	2015	2014	2013	2012
Selected Financial Data						
Operating revenues (000's):						
Electric	**$ 342,805**	$ 322,356	$ 280,615	$ 277,874	$ 257,260	$ 236,895
Natural gas distribution	**848,388**	766,115	817,419	921,986	851,945	754,848
Pipeline and midstream	**122,213**	141,602	154,904	157,292	144,568	142,610
Construction materials and contracting	**1,812,529**	1,874,270	1,904,282	1,765,330	1,712,137	1,617,425
Construction services	**1,367,602**	1,073,272	926,427	1,119,529	1,039,839	938,558
Other	**7,874**	8,643	9,191	9,364	9,620	10,370
Intersegment eliminations	**(58,060)**	(57,430)	(78,786)	(136,302)	(95,201)	(74,595)
	$ 4,443,351	$ 4,128,828	$ 4,014,052	$ 4,115,073	$ 3,920,168	$ 3,626,111
Operating income (loss) (000's):						
Electric	**$ 82,153**	$ 68,497	$ 57,955	$ 61,331	$ 54,274	$ 49,852
Natural gas distribution	**84,878**	65,014	53,810	65,633	78,829	67,579
Pipeline and midstream	**36,924**	43,374	29,988	46,713	20,896	49,139
Construction materials and contracting	**143,716**	178,719	146,026	86,462	93,629	57,864
Construction services	**81,590**	53,705	43,376	82,309	85,246	66,531
Other	**(549)**	(189)	(8,438)	(5,366)	(4,384)	(5,325)
Intersegment eliminations	**—**	—	(2,942)	(9,900)	(7,176)	—
	$ 428,712	$ 409,120	$ 319,775	$ 327,182	$ 321,314	$ 285,640
Earnings (loss) on common stock (000's):						
Electric	**$ 49,366**	$ 42,222	$ 35,914	$ 36,731	$ 34,837	$ 30,634
Natural gas distribution	**32,225**	27,102	23,607	30,484	37,656	29,409
Pipeline and midstream	**20,493**	23,435	13,250	24,666	7,701	26,588
Construction materials and contracting	**123,398**	102,687	89,096	51,510	50,946	32,420
Construction services	**53,306**	33,945	23,762	54,432	52,213	38,429
Other	**(1,422)**	(3,231)	(14,941)	(7,386)	(10,776)	(7,209)
Intersegment eliminations	**6,849**	6,251	5,016	(6,095)	(4,307)	—
Earnings on common stock before income (loss) from discontinued operations	**284,215**	232,411	175,704	184,342	168,270	150,271
Income (loss) from discontinued operations, net of tax*	**(3,783)**	(300,354)	(834,080)	109,311	109,615	(151,710)
Loss from discontinued operations attributable to noncontrolling interest	**—**	(131,691)	(35,256)	(3,895)	(363)	—
	$ 280,432	$ 63,748	$ (623,120)	$ 297,548	$ 278,248	$ (1,439)
Earnings (loss) per common share before discontinued operations - diluted	**$ 1.45**	$ 1.19	$ .90	$ .96	$ .89	$ .80
Discontinued operations attributable to the Company, net of tax	**(.02)**	(.86)	(4.10)	.59	.58	(.81)
	$ 1.43	$ .33	$ (3.20)	$ 1.55	$ 1.47	$ (.01)
Common Stock Statistics						
Weighted average common shares outstanding -diluted (000's)	**195,687**	195,618	194,986	192,587	189,693	188,826
Dividends declared per common share	**$ .7750**	$ .7550	$ .7350	$ .7150	$ .6950	$ .6750
Book value per common share	**$ 12.44**	$ 11.78	$ 12.83	$ 16.66	$ 15.01	$ 13.95
Market price per common share (year end)	**$ 26.88**	$ 28.77	$ 18.32	$ 23.50	$ 30.55	$ 21.24
Market price ratios:						
Dividend payout**	**53%**	63%	82%	74%	78%	84%
Yield	**2.9%**	2.7%	4.1%	3.1%	2.3%	3.2%
Market value as a percent of book value	**216.1%**	244.2%	142.8%	141.1%	203.5%	152.3%

* 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)

	2017	2016	2015	2014	2013	2012
General						
Total assets (000's)	**$ 6,334,666**	$ 6,284,467	$ 6,565,154	$ 7,805,405	$ 7,043,365	$ 6,675,609
Total long-term debt (000's)	**$ 1,714,853**	$ 1,790,159	$ 1,796,163	$ 2,016,198	$ 1,773,050	$ 1,738,833
Capitalization ratios:						
Total equity	**59%**	56%	58%	62%	62%	60%
Total debt	**41**	44	42	38	38	40
	100%	100%	100%	100%	100%	100%
Electric						
Retail sales (thousand kWh)	**3,306,470**	3,258,537	3,316,017	3,308,358	3,173,086	2,996,528
Electric system summer and firm purchase contract ZRCs (Interconnected system)	**553.1**	559.7	547.3	584.0	583.5	552.8
Electric system peak demand obligation, including firm purchase contracts, planning reserve margin requirement (Interconnected system)	**530.2**	559.7	547.3	522.4	508.3	550.7
All-time demand peak - kW (Interconnected system)	**611,542**	611,542	611,542	582,083	573,587	573,587
Electricity produced (thousand kWh)	**2,630,640**	2,626,763	1,898,160	2,519,938	2,430,001	2,299,686
Electricity purchased (thousand kWh)	**955,687**	904,702	1,658,002	1,010,422	971,261	870,516
Average cost of electric fuel and purchased power per kWh	**$ .022**	$ .021	$ .024	$ .025	$ .025	$ .023
Natural Gas Distribution						
Sales (Mdk)	**112,551**	99,296	95,559	104,297	108,260	93,810
Transportation (Mdk)	**144,477**	147,592	154,225	145,941	149,490	132,010
Degree days (% of normal)						
Montana-Dakota/Great Plains	**100%**	89%	88%	103%	105%	84%
Cascade	**107%**	87%	83%	89%	98%	96%
Intermountain	**111%**	96%	89%	95%	110%	91%
Pipeline and Midstream						
Transportation (Mdk)	**312,520**	285,254	290,494	233,483	178,598	137,720
Gathering (Mdk)	**16,064**	20,049	33,441	38,372	40,737	47,084
Customer natural gas storage balance (Mdk)	**22,397**	26,403	16,600	14,885	26,693	43,731
Construction Materials and Contracting						
Sales (000's):						
Aggregates (tons)	**28,213**	27,580	26,959	25,827	24,713	23,285
Asphalt (tons)	**6,237**	7,203	6,705	6,070	6,228	5,988
Ready-mixed concrete (cubic yards)	**3,548**	3,655	3,592	3,460	3,223	3,157
Aggregate reserves (000's tons)	**965,036**	989,084	1,022,513	1,061,156	1,083,376	1,088,236

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

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 opportunities and strategic acquisitions. The Company is focused on a disciplined approach to the acquisition of well-managed companies and properties.

The Company has capabilities to fund its growth and operations through various sources, including internally generated funds, commercial paper facilities, revolving credit facilities, and the issuance from time to time of debt and equity securities. For more information on the Company's capital expenditures, see Liquidity and Capital Commitments.

On December 22, 2017, President Trump signed into law the TCJA making significant changes to the United States federal income tax laws. Some of the more material changes from the TCJA impacting the Company includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. During the fourth quarter of 2017, the Company performed a one-time revaluation of the net deferred tax liabilities to account for the reduction in the corporate tax rate from 35 percent to 21 percent, as discussed in Item 8 - Note 11. The Company is currently reviewing the components of the TCJA and evaluating the impact on the Company for 2018 and thereafter. For information pertinent to the specific impacts or trends identified by the Company's business segments, see Business Segment Financial and Operating Data.

Consolidated Earnings Overview

The following table summarizes the contribution to consolidated earnings (loss) by each of the Company's business segments.

Years ended December 31,	**2017**	2016	2015
	(In millions, except per share amounts)		
Electric	**$ 49.4**	$ 42.2	$ 35.9
Natural gas distribution	**32.2**	27.1	23.6
Pipeline and midstream	**20.5**	23.4	13.3
Construction materials and contracting	**123.4**	102.7	89.1
Construction services	**53.3**	33.9	23.8
Other	**(1.5)**	(3.2)	(15.0)
Intersegment eliminations	**6.9**	6.3	5.0
Earnings before discontinued operations	**284.2**	232.4	175.7
Loss from discontinued operations, net of tax	**(3.8)**	(300.4)	(834.1)
Loss from discontinued operations attributable to noncontrolling interest	**—**	(131.7)	(35.3)
Earnings (loss) on common stock	**$ 280.4**	$ 63.7	$ (623.1)
Earnings (loss) per common share - basic:			
Earnings before discontinued operations	**$ 1.46**	$ 1.19	$ .90
Discontinued operations attributable to the Company, net of tax	**(.02)**	(.86)	(4.10)
Earnings (loss) per common share - basic	**$ 1.44**	$ .33	$ (3.20)
Earnings (loss) per common share - diluted:			
Earnings before discontinued operations	**$ 1.45**	$ 1.19	$ .90
Discontinued operations attributable to the Company, net of tax	**(.02)**	(.86)	(4.10)
Earnings (loss) per common share - diluted	**$ 1.43**	$ .33	$ (3.20)

2017 compared to 2016 The Company recognized consolidated earnings of $280.4 million in 2017, compared to consolidated earnings of $63.7 million in 2016. This increase was the result of:

- Discontinued operations which reflect the absence in 2017 of a loss associated with the sale of the refining business in June 2016
- An income tax benefit of $39.5 million primarily for the revaluation of the Company's net deferred tax liabilities, as discussed in Item 8 - Note 11
- Higher inside and outside specialty contracting margins at the construction services business
- Higher natural gas retail sales margins at the natural gas distribution business
- Higher electric retail sales margins at the electric business

These increases were partially offset by:

- Lower asphalt product margins and lower construction margins at the construction materials and contracting business

- Lower gathering and processing revenues at the pipeline and midstream business

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, asphalt product and aggregate margins at the construction materials and contracting business
- Other loss decreased primarily as the result of lower operation and maintenance and interest expense due to the sales of the exploration and production and refining businesses
- Higher inside construction margins offset in part by lower outside construction margins, which includes lower equipment sales and rental margins, at the construction services business
- Lower impairment in 2016 at the pipeline and midstream business
- Higher electric retail sales margins offset in part by higher operation and maintenance expense and higher depreciation, depletion and amortization expense at the electric business

Business Segment Financial and Operating Data

Following are key financial and operating data for each of the Company's business segments. Also included are highlights on key growth strategies, projections and certain assumptions for the Company and its subsidiaries and other matters of the Company's business segments. 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 results to differ materially from the Company's growth and earnings projections.

For information pertinent to various commitments and contingencies, see Item 8 - Notes to Consolidated Financial Statements. For a summary of the Company's business segments, see Item 8 - Note 13.

Electric and Natural Gas Distribution

Strategy and challenges The electric and natural gas distribution segments provide electric and natural gas distribution services to customers, as discussed in Items 1 and 2 - Business Properties. Both segments strive to be a top performing utility company measured by integrity, safety, employees, customer service and shareholder performance, while continuing to focus on providing safe, reliable and competitively priced energy and related services to customers. The Company continues to monitor opportunities for these segments 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 to earn a competitive return on investment. The continued efforts to create operational improvements and efficiencies across both segments promotes the Company's business integration strategy. The primary factors that impact the results of these segments are the ability to earn authorized rates of return, the cost of natural gas, cost of electric fuel and purchased power, competitive factors in the energy industry and economic conditions in the segments' service areas.

The electric and natural gas distribution segments are subject to extensive regulation in the jurisdictions where they conduct operations with respect to costs, timely recovery of investments and permitted returns on investment as well as certain operational, system integrity and environmental regulations. To assist in the reduction of regulatory lag with the increase in investments, tracking mechanisms have been implemented. 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 result in the retirement of certain electric generating facilities before they are fully depreciated. Although the current administration has slowed environmental regulations, the segments continue to invest in facility upgrades to be in compliance with the existing and future regulations.

The ability to grow through acquisitions is subject to significant competition and acquisition premiums. In addition, the ability of the segments to grow their 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.

Revenues are impacted by both customer growth and usage, the latter of which is primarily impacted by weather. Very cold winters increase demand for natural gas and to a lesser extent, electricity, while warmer than normal summers increase demand for electricity, especially among residential and commercial customers. Average consumption among natural gas customers has tended to decline as more efficient appliances and furnaces are installed, and as the Company has implemented conservation programs. Decoupling mechanisms in certain jurisdictions have been implemented to largely mitigate the effect that would otherwise be caused by variations in volumes sold to these customers due to weather and changing consumption patterns.

Earnings overview - electric The following information summarizes the performance of the electric segment.

Years ended December 31,	2017	2016	2015
	(Dollars in millions, where applicable)		
Operating revenues	**$ 342.8**	$ 322.3	$ 280.6
Operating expenses:			
Operation and maintenance	**120.0**	115.2	87.7
Electric fuel and purchased power	**78.7**	75.5	86.2
Depreciation, depletion and amortization	**47.7**	50.2	37.6
Taxes, other than income	**14.3**	12.9	11.1
Total operating expenses	**260.7**	253.8	222.6
Operating income	**82.1**	68.5	58.0
Earnings	**$ 49.4**	$ 42.2	$ 35.9
Retail sales (million kWh):			
Residential	**1,153.5**	1,132.5	1,173.9
Commercial	**1,513.1**	1,491.8	1,499.6
Industrial	**539.9**	544.2	550.3
Other	**100.0**	90.0	92.2
	3,306.5	3,258.5	3,316.0
Average cost of electric fuel and purchased power per kWh	**$ .022**	$ .021	$ .024

2017 compared to 2016 Electric earnings increased $7.2 million (17 percent) compared to the prior year. The increase resulted from:

- Increased electric retail sales margins from the recovery of additional investment in a MISO multivalue project, approved rate recovery in all jurisdictions and 2 percent higher retail sales volumes to commercial and residential customers
- Lower depreciation, depletion and amortization expense of $1.5 million (after tax) from lower depreciation rates implemented in conjunction with regulatory recovery activity

Partially offsetting the increase were:

- Higher operation and maintenance expense of $3.0 million (after tax) largely from higher payroll-related costs, material costs and contract services
- Income tax expense of $2.1 million for the revaluation of nonutility net deferred tax assets, as discussed in Item 8 - Note 11

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 from decreased residential customer volumes
- Favorable income tax changes, which includes $10.1 million due to higher production tax credits

Partially offsetting these increases 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 electric fuel and purchased power per kWh due to no electric fuel and purchased power costs associated with the Thunder Spirit Wind farm in 2016 as compared to 2015.

Earnings overview - natural gas distribution The following information summarizes the performance of the natural gas distribution segment.

Years ended December 31,		2017		2016		2015
		(Dollars in millions, where applicable)				
Operating revenues	$	848.4	$	766.1	$	817.4
Operating expenses:						
Operation and maintenance		163.7		158.1		153.5
Purchased natural gas sold		479.9		431.5		499.0
Depreciation, depletion and amortization		69.4		65.4		64.8
Taxes, other than income		50.5		46.1		46.3
Total operating expenses		763.5		701.1		763.6
Operating income		84.9		65.0		53.8
Earnings	$	32.2	$	27.1	$	23.6
Volumes (MMdk)						
Retail sales:						
Residential		63.6		56.2		54.0
Commercial		44.3		38.9		37.6
Industrial		4.6		4.2		4.0
		112.5		99.3		95.6
Transportation sales:						
Commercial		2.0		1.8		1.8
Industrial		142.5		145.8		152.4
		144.5		147.6		154.2
Total throughput		257.0		246.9		249.8
Degree days (% of normal)*						
Montana-Dakota/Great Plains		100%		89%		88%
Cascade		107%		87%		83%
Intermountain		111%		96%		89%
Average cost of natural gas, including transportation, per dk	$	4.26	$	4.35	$	5.22

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

2017 compared to 2016 The natural gas distribution business experienced an increase in earnings of $5.1 million (19 percent) compared to the prior year because of increased natural gas retail sales margins. The margin increase resulted from:

- Increased retail sales volumes of 13 percent across all customer classes from colder weather in all jurisdictions, offset in part by weather normalization in certain jurisdictions, and 2 percent customer growth
- Approved final and interim rate increases

Partially offsetting the increase were:

- Income tax expense of $4.3 million for the revaluation of nonutility net deferred tax assets, as discussed in Item 8 - Note 11
- Higher operation and maintenance expense, which includes $3.7 million (after tax) largely from higher payroll-related costs and material costs
- Higher depreciation, depletion and amortization expense of $2.4 million (after tax) as a result of increased property, plant and equipment balances

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 from higher natural gas retail sales margins. The margin increase resulted from:

- Increased retail sales volumes of 4 percent to all customer classes from customer growth and colder weather in certain regions
- Approved final and interim rate increases

Partially offsetting the increase were higher operation and maintenance expense, which includes $4.6 million (after tax) largely from 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.

Outlook The Company expects these segments will grow rate base by approximately 6 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. Operations are spread across eight states where the Company expects customer growth to be higher than the national average. Customer growth is expected to grow by 1 percent to 2 percent per year. 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 natural gas systems.

The Company continues to be focused on the regulatory recovery of its investments. Since, January 1, 2017, these segments have implemented rate increases in Idaho, Minnesota, Montana, North Dakota, Oregon, Wyoming and before the FERC. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in Item 8 - Note 16.

With the enactment of the TCJA, the state regulators in jurisdictions where the segments operate have requested companies submit plans for the estimated impact of the TCJA. As such, the segments are using the deferral method of accounting for the revaluation of its regulated deferred tax assets and liabilities. The impact of the revaluation of the segments' regulatory deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment, have been included in the Company's regulatory assets and liabilities, as discussed in Item 8 - Note 4. The Company does not anticipate the corporate tax rate reduction to increase earnings at the utility businesses. The Company anticipates the TCJA will negatively impact the segments' cash flows due to not being able to immediately expense utility property.

In December 2016, the Company signed a 25-year agreement to purchase power from the expansion of the Thunder Spirit Wind farm in southwest North Dakota. In November 2017, the NDPSC approved the advance determination of prudence for the purchase of the Thunder Spirit Wind farm expansion. The Company expects to soon have a purchase agreement in place and finalize the purchase when the construction is complete in late 2018. With the addition of the expansion, the Company's total wind farm generation capacity will be approximately 155 MW and increase the Company's electric generation portfolio to approximately 27 percent renewables based on nameplate ratings. The Company's integrated resource plans in North Dakota and Montana include additional generation projects.

In June 2016, the Company, along with a partner, began construction on a 345-kilovolt transmission line from Ellendale, North Dakota, to Big Stone City, South Dakota. The estimated capital investment for this project is $130 million to $150 million. All necessary easements have been secured and the project is expected to be completed in 2019.

In 2018, the Company will begin the construction of a new 12-inch natural gas pipeline that will run approximately 21 miles from northeast Milnor, North Dakota, to southwest of Gwinner, North Dakota. The pipeline will serve, in part, a manufacturing facility in Gwinner and is expected to be in service by late 2018. The pipeline has the capacity to expand natural gas service to other key industries in the region.

Pipeline and Midstream

Strategy and challenges The pipeline and midstream segment provides natural gas transportation, gathering and underground storage services, as discussed in Items 1 and 2 - Business Properties. The segment focuses on utilizing its extensive expertise in the design, construction and operation of energy infrastructure and related services to increase market share and profitability through optimization of existing operations, organic growth, and investments in energy-related assets within or in close proximity to its current operating areas. The segment focuses on the continual safety and reliability of its systems, which entails building and maintaining safe natural gas pipelines and facilities. The segment continues to evaluate growth opportunities including the expansion of existing storage, gathering and transmission facilities; incremental pipeline projects which expand pipeline capacity; and expansion of energy-related services in the region leveraging on core competencies.

The segment is exposed to energy price volatility which is impacted by the fluctuations in pricing, production and basis differentials of the energy market's commodities. Legislative and regulatory initiatives to increase pipeline safety regulations and reduce methane emissions could also impact the price and demand for natural gas.

The pipeline and midstream segment is subject to extensive regulation including certain operational, system integrity and environmental regulations as well as various permit terms and operational compliance conditions. The segment is charged with the ongoing process of reviewing existing permits and easements as well as securing new permits and easements as necessary to meet current demand and future growth opportunities. Exposure to pipeline opposition groups could also cause negative impacts on the segment with increased costs and potential delays to project completion.

The segment focuses on the recruitment and retention of a skilled workforce to remain competitive and provide services to its customers. The industry in which it operates relies on a skilled workforce to construct energy infrastructure and operate existing infrastructure in a safe manner. A shortage of skilled personnel can create a competitive labor market which could increase costs incurred by the segment. Competition from other pipeline and midstream companies can also have a negative impact on the segment.

Earnings overview - pipeline and midstream The following information summarizes the performance of the pipeline and midstream segment.

Years ended December 31,	2017	2016	2015
		(Dollars in millions)	
Operating revenues	**$ 122.2**	$ 141.6	$ 154.9
Operating expenses:			
Operation and maintenance	**56.0**	61.4	84.7
Depreciation, depletion and amortization	**16.8**	24.9	28.0
Taxes, other than income	**12.5**	11.9	12.2
Total operating expenses	**85.3**	98.2	124.9
Operating income	**36.9**	43.4	30.0
Earnings	**$ 20.5**	$ 23.4	$ 13.3
Transportation volumes (MMdk)	**312.5**	285.3	290.5
Natural gas gathering volumes (MMdk)	**16.1**	20.0	33.4
Customer natural gas storage balance (MMdk):			
Beginning of period	**26.4**	16.6	14.9
Net injection (withdrawal)	**(4.0)**	9.8	1.7
End of period	**22.4**	26.4	16.6

2017 compared to 2016 Pipeline and midstream earnings decreased $2.9 million (13 percent) compared to the prior year largely resulting from lower gathering and processing revenues of $14.0 million (after tax). The decrease in revenues resulted from lower volumes from the sale of the Pronghorn assets in January 2017, as discussed in Item 8 - Note 2. Also included in the decrease in earnings was income tax expense of $200,000 for the TCJA revaluation, as discussed in Item 8 - Note 11.

Partially offsetting the decrease were:

- Lower depreciation, depletion and amortization expense of $5.0 million (after tax) resulting from the absence of the Pronghorn assets, as previously discussed
- Lower operation and maintenance expense, which includes $2.2 million (after tax) primarily from the absence of Pronghorn, as previously discussed, as well as the absence in 2017 of a $1.4 million (after tax) fair value impairment in 2016 associated with the Pronghorn sale
- Lower interest expense due to lower debt balances
- Higher transportation revenues of $1.0 million largely resulting from increased off-system transportation volumes due to recently completed organic growth projects

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

Outlook The Company has continued to feel the effects of natural gas production at record levels which keeps downward pressure on natural gas prices in the near term. The Company continues to focus on growth and improving existing operations through organic projects in all areas in which it operates. The following describes recent growth projects.

The Company's Valley Expansion project, a 38-mile pipeline that will deliver natural gas supply to eastern North Dakota and far western Minnesota, is expected to be complete in the fourth quarter of 2018. The project, which is designed to transport 40 million cubic feet of natural gas per day, is under the jurisdiction of the FERC. In February 2018, the Company received an order issuing a certificate of public convenience and necessity from the FERC. Construction is expected to begin as soon as the conditions of the certificate have been met, including the receipt of outstanding permits.

In June 2017, the Company announced plans to complete a Line Section 27 expansion project in the Bakken area of northwestern North Dakota. The project will include approximately 13 miles of new pipeline and associated facilities. The project, as designed, will increase capacity by over 200 million cubic feet per day and bring total capacity of the Line Section 27 to over 600 million cubic feet per day. The project is expected to be placed in service in the fall of 2018.

In 2017, the Company completed and placed into service the Charbonneau and Line Section 25 expansion projects, which include a new compression station as well as other compressor additions and enhancements at existing stations. The Company's revenues have been positively impacted by the increase in transportation volumes with these projects.

The impact of the TCJA on the pipeline and midstream industry is uncertain. With the enactment of the TCJA, the regulated pipeline is using the deferral method of accounting for the revaluation of its regulated deferred tax assets and liabilities. The impact of the revaluation of the regulated pipeline's regulatory deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment, have been included in the Company's regulatory assets and liabilities, as discussed in Item 8 - Note 4.

Construction Materials and Contracting

Strategy and challenges The construction materials and contracting segment provides an integrated set of construction services, as discussed in Items 1 and 2 - Business Properties. The segment focuses on high-growth strategic markets located near major transportation corridors and desirable mid-sized metropolitan areas; strengthening the long-term, strategic aggregate reserve position through available purchase and/or lease opportunities; enhancing profitability through cost containment, margin discipline and vertical integration of the segment's operations; development and recruitment of talented employees; and continued growth through organic and acquisition opportunities.

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 segment's expertise. The segment 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.

As one of the country's largest sand and gravel producers, the segment 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. The segment's 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.

The construction materials and contracting segment faces challenges that are not under the direct control of the business. The segment operates in highly competitive markets. Competition can put negative pressure on the ability of the segment to earn a reasonable return. The segment is also subject to volatility in the cost of raw materials such as diesel, gasoline, liquid asphalt, cement and steel. Such volatility can have a negative impact on the segment's margins. Other variables that can impact the segment's margins include adverse weather conditions, the timing of project starts or completion and declines or delays in new and existing projects due to the cyclical nature of the construction industry.

The segment also faces challenges in the recruitment and retention of employees. Trends in the labor market include an aging workforce and availability issues. The segment also faces increasing pressure to reduce costs and the need for temporary employment because of the seasonality of the work performed in certain regions.

Earnings overview - construction materials and contracting The following information summarizes the performance of the construction materials and contracting segment.

Years ended December 31,	2017	2016	2015
		(Dollars in millions)	
Operating revenues	**$ 1,812.5**	$ 1,874.3	$ 1,904.3
Operating expenses:			
Cost of sales:			
Operation and maintenance	**1,500.7**	1,533.2	1,576.4
Depreciation, depletion and amortization	**52.5**	54.1	61.0
Taxes, other than income	**38.0**	37.5	36.1
	1,591.2	1,624.8	1,673.5
Selling, general and administrative expense:			
Operation and maintenance	**70.4**	62.2	75.9
Depreciation, depletion and amortization	**3.4**	4.3	4.9
Taxes, other than income	**3.8**	4.3	4.0
	77.6	70.8	84.8
Total operating expenses	**1,668.8**	1,695.6	1,758.3
Operating income	**143.7**	178.7	146.0
Earnings	**$ 123.4**	$ 102.7	$ 89.1
Sales (000's):			
Aggregates (tons)	**28,213**	27,580	26,959
Asphalt (tons)	**6,237**	7,203	6,705
Ready-mixed concrete (cubic yards)	**3,548**	3,655	3,592

2017 compared to 2016 Earnings at the construction materials and contracting business increased $20.7 million (20 percent) compared to the prior year. The increase was the result of:

- An income tax benefit of $41.9 million for the revaluation of the segment's net deferred tax liabilities, as discussed in Item 8 - Note 11
- Higher aggregate margins of $5.0 million (after tax) primarily due to strong commercial and residential demand in certain regions

Partially offsetting these increases were:

- Lower asphalt product margins resulting from lower revenues driven by competitive pricing and lower volumes from unfavorable weather during the first half of the year, less available work and increased competition in certain regions
- Lower construction margins of $5.5 million (after tax), largely decreased workloads caused by unfavorable weather during the first half of the year and less available work in energy-producing states
- Higher selling, general and administrative expense of $4.1 million (after tax) from the absence in 2017 of a $6.7 million (after tax) reduction to a MEPP withdrawal liability, as discussed in Item 8 - Note 14, offset in part by lower depreciation, depletion and amortization and lower office expense

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

- Higher construction margins of $8.1 million (after tax) resulting from higher revenues due to more available work in most regions
- Lower selling, general and administrative expense from 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 asphalt product margins of $2.9 million (after tax) resulting from higher volumes and lower asphalt oil and production costs
- Higher aggregate margins of $2.3 million (after tax) resulting from higher volumes due to increased demand

Partially offsetting these increases were:

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

Lower diesel fuel costs contributed to higher earnings from all product lines in 2016.

Outlook The segment's vertically integrated aggregates based business model provides the Company with the ability to capture margin throughout the sales delivery process. The aggregate products are sold internally and externally for use in other products such as ready-mixed concrete, asphaltic concrete and public and private construction markets. The contracting services and construction materials are sold primarily to construction contractors in connection with street, highway and other public infrastructure projects, as well as private commercial and residential development projects. The public infrastructure projects have traditionally been more stable markets as public funding is more secure during periods of economic decline. The public funding is, however, dependent on federal funding such as appropriations to the Federal Highway Administration. Spending on private development is highly dependent on both local and national economic cycles, providing additional sales during times of strong economic cycles.

The Company remains optimistic about overall economic growth and infrastructure spending. The IBIS World Industry Report for sand and gravel mining in the United States projects a 2.7 percent annual growth rate over the next five years. The report also states the demand for clay and refractory materials is projected to continue deteriorating in several downstream manufacturing industries, but this decline will be offset by stronger demand from the housing market and buoyant demand from the highway and bridge construction market. This stronger demand in the housing markets along with continued demand from the highway and bridge construction markets should provide a stable demand for construction materials and contracting products and services in the near future.

The impact of the TCJA on the economy as a whole is unclear at this time. As such, the impact to the construction materials and contracting industry is also uncertain. Under the TCJA, the domestic production deduction will no longer be able to be taken. The domestic production deduction was originally introduced to incentivize domestic production activities and was a deduction of up to 9 percent on qualified production activity income for which this segment's activities qualified. The Company expects the lower federal corporate tax rate will more than offset the loss of the domestic production deduction for this segment.

Construction Services

Strategy and challenges The construction services segment provides inside and outside specialty contracting, as discussed in Items 1 and 2 - Business Properties. The construction services segment focuses on providing a superior return on investment by building new and strengthening existing customer relationships; ensuring quality service; safely executing projects; effectively controlling costs; collecting on receivables; 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.

The construction services segment faces challenges in the highly competitive markets in which it operates. Competitive pricing environments, project delays and effects from restrictive regulatory requirements have negatively impacted margins in the past and could affect margins in the future. Additionally, margins may be negatively impacted on a quarterly basis due to adverse weather conditions, as well as timing of project starts or completions, declines or delays in new projects due to the cyclical nature of the construction industry and other factors. These challenges may also impact the risk of loss on certain projects. Accordingly, operating results in any particular period may not be indicative of the results that can be expected for any other period.

The need to ensure available specialized labor resources for projects also drives strategic relationships with customers and project margins. These trends include an aging workforce and labor availability issues, increasing pressure to reduce costs and improve reliability, and increasing duration and complexity of customer capital programs. Due to these and other factors, we believe customer demand for labor resources will continue to increase, possibly outpacing, the supply of industry resources.

Earnings overview - construction services The following information summarizes the performance of the construction services segment.

Years ended December 31,	2017	2016	2015
		(In millions)	
Operating revenues	**$ 1,367.6**	$ 1,073.3	$ 926.4
Operating expenses:			
Cost of sales:			
Operation and maintenance	**1,153.9**	905.4	783.7
Depreciation, depletion and amortization	**14.2**	13.5	11.8
Taxes, other than income	**43.4**	35.2	27.4
	1,211.5	954.1	822.9
Selling, general and administrative expense:			
Operation and maintenance	**69.0**	59.9	54.8
Depreciation, depletion and amortization	**1.5**	1.8	1.6
Taxes, other than income	**4.0**	3.8	3.7
	74.5	65.5	60.1
Total operating expenses	**1,286.0**	1,019.6	883.0
Operating income	**81.6**	53.7	43.4
Earnings	**$ 53.3**	$ 33.9	$ 23.8

2017 compared to 2016 Construction services earnings increased $19.4 million (57 percent) compared to the prior year largely because of:

- Higher inside specialty contracting margins of $12.8 million (after tax) driven by an increase in revenues from an increase in the number and size of construction projects in 2017 and decreased costs from the successful management of labor performance on projects in a majority of the business activities performed partially offset by job losses on certain projects
- Higher outside specialty contracting margins of $9.8 million (after tax) driven by higher contracting workloads and equipment revenues in areas impacted by storm activity
- An income tax benefit of $4.3 million for the revaluation of the segment's net deferred tax liabilities, as discussed in Item 8 - Note 11

Partially offsetting these increases were:

- Higher selling, general and administrative expense, largely payroll-related costs
- The absence in 2017 of a $1.5 million tax benefit related to the disposition of a non-strategic asset

2016 compared to 2015 Construction services earnings increased $10.1 million (43 percent) compared to the prior year largely because of:

- Higher inside specialty contracting margins of $13.0 million (after tax) resulting from higher workloads 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 partially offset by a loss on a project
- Higher margins 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 outside construction margins, primarily lower equipment revenues impacted by decreased customer demand

Outlook The Company continues to expect long-term growth in the electric transmission market, although the timing of large bids and subsequent construction is likely to be highly variable from year to year. The Company believes several multi-year transmission projects will be available for bid in the 2018 timeframe and also expects bidding activity in small and medium-sized transmission and distribution projects to continue in 2018.

The impact of the TCJA on the economy as a whole is unclear at this time. As such, the impact to the construction services industry is also uncertain. While it is unclear what impact the TCJA may have on the construction services industry, the Company is optimistic about overall economic growth and infrastructure spending and believes that improving industry activity will continue in both market segments and the drivers for investment will remain intact. The Company believes that regulatory reform, state renewable portfolio standards, the aging of the electric grid, and the general improvement of the economy will positively impact the level of spending by its customers. Although competition remains strong, these trends are viewed as positive factors in the future.

The Company expects bidding activity to remain strong in both outside and inside specialty construction companies for the year 2018. Although bidding remains highly competitive in all areas, the Company expects the segment's skilled workforce will continue to provide a benefit in securing and executing profitable projects.

Other

Years ended December 31,	2017	2016	2015
		(In millions)	
Operating revenues	$ 7.9	$ 8.6	$ 9.2
Operating expenses:			
Operation and maintenance	6.2	6.6	15.4
Depreciation, depletion and amortization	2.0	2.1	2.1
Taxes, other than income	.2	.1	.1
Total operating expenses	8.4	8.8	17.6
Operating loss	(.5)	(.2)	(8.4)
Loss	$ (1.5)	$ (3.2)	$ (15.0)

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.

2017 compared to 2016 Other loss decreased $1.7 million compared to the prior year primarily the result of lower interest expense from the repayment of long-term debt with the sale of the remaining exploration and production assets. Lower operation and maintenance expense was due to the absence of the refining business in 2017 offset in part by the loss on the disposition of certain assets during the year.

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.

Discontinued Operations

Years ended December 31,	2017	2016	2015
		(In millions)	
Income (loss) from discontinued operations before intercompany eliminations, net of tax	$ 3.1	$ (303.2)	$ (829.9)
Intercompany eliminations*	(6.9)	2.8	(4.2)
Loss from discontinued operations, net of tax	(3.8)	(300.4)	(834.1)
Loss from discontinued operations attributable to noncontrolling interest	—	(131.7)	(35.3)
Loss from discontinued operations attributable to the Company, net of tax	$ (3.8)	$ (168.7)	$ (798.8)

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

2017 compared to 2016 The loss from discontinued operations attributable to the Company was $3.8 million compared to a loss of $168.7 million in the prior year. The decreased loss was largely due to the absence in 2017 of a loss associated with the sale of the refining business in June 2016, as well as the reversal in 2017 of a previously accrued liability due to the resolution of a legal matter, as discussed in Item 8 - Note 2.

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.

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 related to these items were as follows:

Years ended December 31,	2017	2016	2015
		(In millions)	
Intersegment transactions:			
Operating revenues	**$ 58.0**	$ 57.4	$ 78.8
Operation and maintenance	**9.1**	8.7	26.9
Purchased natural gas sold	**48.9**	48.7	48.9
Income from continuing operations*	**(6.9)**	(6.3)	(5.0)

* 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.

New Accounting Standards

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

Liquidity and Capital Commitments

At December 31, 2017, the Company had cash and cash equivalents of $34.6 million and available borrowing capacity of $687.1 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 and its other operating and capital requirements from various sources, including internally generated funds; the Company's credit facilities, as described later in Capital resources; the issuance of long-term debt; and issuance of equity securities.

Cash flows

Operating activities The changes in cash flows from operating activities generally follow the results of operations as discussed in Business Segment 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 2017 decreased $14.2 million from 2016. The decrease in cash flows provided by operating activities reflects higher working capital requirements at the construction services business largely resulting from higher receivables due to increased workloads during the year and at the construction materials business due to higher receivables resulting from increased workloads later in the year. Higher natural gas purchases including the effects of colder weather also added to higher working capital requirements at the natural gas distribution business. Higher income taxes paid from continuing operations was largely offset by higher income taxes received from discontinued operations resulting from the realization of net operating losses at the discontinued operations. Higher earnings from continuing operations in 2017, compared to 2016, partially offset the decrease in cash flows provided by operating activities. Higher margins at the electric, natural gas distribution and construction services businesses were partially offset by lower margins at the construction materials business.

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.

Investing activities Cash flows used in investing activities in 2017 decreased $90.9 million from 2016 largely resulting from net proceeds from the sale of Pronghorn in January 2017 at the pipeline and midstream business.

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 were lower proceeds from the sale of properties at the exploration and production business.

Financing activities Cash flows used in financing activities in 2017 increased $50.4 million from 2016 primarily due to the higher net repayment of long-term debt.

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.

Defined benefit pension plans

The Company has noncontributory qualified 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, 2017, the pension plans' accumulated benefit obligations exceeded these plans' assets by approximately $91.5 million. Pretax pension expense reflected in the years ended December 31, 2017, 2016 and 2015, was $1.7 million, $2.1 million and $2.0 million, respectively. The Company's pension expense is currently projected to be approximately $2.0 million to $3.0 million in 2018. Funding for the pension plans is actuarially determined. The minimum required contributions for 2017 and 2015 were approximately $3.1 million and $3.9 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 2015 through 2017 and as anticipated for 2018 through 2020 are summarized in the following table.

	Actual (a)			Estimated		
	2015	2016	**2017**	2018	2019	2020
			(In millions)			
Capital expenditures:						
Electric	$ 333	$ 111	**$ 109**	$ 229	$ 107	$ 98
Natural gas distribution	131	126	**147**	203	211	172
Pipeline and midstream	18	35	**31**	97	100	109
Construction materials and contracting	48	38	**44**	79	78	76
Construction services	38	60	**19**	17	16	16
Other	4	2	**2**	3	2	1
Total capital expenditures	$ 572	$ 372	**$ 352**	$ 628	$ 514	$ 472

(a) Capital expenditures for 2017, 2016 and 2015 include noncash capital expenditure-related accounts payable and AFUDC, totaling $10.5 million, $(15.8) million and $35.3 million, respectively.

The 2017 capital expenditures were met from internal sources. The Company has included in the estimated capital expenditures for 2018 the purchase of the Thunder Spirit Wind farm expansion, the Valley Expansion project and the Line Section 27 expansion project, as previously discussed in Business Segment Financial and Operating Data.

Estimated capital expenditures for the years 2018 through 2020 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 2018 through 2020 will be met from various sources, including internally generated funds; the Company's credit facilities, as described later; issuance of long-term debt; and issuance of equity securities.

Capital resources

Certain debt instruments of the Company and its subsidiaries, including those discussed later, contain restrictive covenants and cross-default provisions. In order to borrow under the respective credit agreements, the Company and its subsidiaries must be in compliance with the applicable covenants and certain other conditions, all of which the Company and its subsidiaries, as applicable, were in compliance with at December 31, 2017. 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, 2017:

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		$ 73.8	(b)	$ —		5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement		$ 75.0	(c)	$ 17.3		$ 2.2	(d)	4/24/20
Intermountain Gas Company	Revolving credit agreement		$ 85.0	(e)	$ 40.0		$ —		4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement	(f)	$ 500.0		$ 14.6	(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 revolving credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $100.0 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 $110.0 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 revolving 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 Company's coverage of fixed charges including preferred stock dividends was 4.2 times and 3.9 times for the 12 months ended December 31, 2017 and 2016, respectively. The coverage of fixed charges is used as an indicator of the Company's ability to satisfy fixed charges.

Total equity as a percent of total capitalization was 59 percent and 56 percent at December 31, 2017 and 2016, 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 is an indicator of how the Company is financing its operations, as well as its financial strength.

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. Historically, 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 in the future, 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.

Cascade Natural Gas Corporation On April 25, 2017, Cascade amended its revolving credit agreement to increase the borrowing limit from $50.0 million to $75.0 million and extend the termination date from July 9, 2018 to April 24, 2020. 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 On April 25, 2017, Intermountain amended its revolving credit agreement to increase the borrowing limit from $65.0 million to $85.0 million and extend the termination date from July 13, 2018 to April 24, 2020. 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.

Centennial Energy Holdings, Inc. 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. Historically, 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 in the future, 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. WBI Energy Transmission has a $200.0 million uncommitted note purchase and private shelf agreement with an expiration date of May 16, 2019. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2017, which reduced the remaining capacity under this uncommitted private shelf agreement to $100.0 million. On December 22, 2017, WBI Energy Transmission contracted to issue an additional $40.0 million under the private shelf agreement at an interest rate of 4.18 percent on June 15, 2018.

Off balance sheet arrangements

As of December 31, 2017, the Company had no material off balance sheet arrangements as defined by the rules of the SEC.

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, 2017, the Company's commitments under these obligations were as follows:

	2018	2019	2020	2021	2022	Thereafter	Total
				(In millions)			
Long-term debt	$ 148.5	$ 125.5	$ 73.0	$ 15.3	$ 147.2	$ 1,211.0	$ 1,720.5
Estimated interest payments*	71.2	62.6	62.2	59.1	58.7	512.9	826.7
Operating leases	55.5	45.3	33.2	18.6	7.0	40.8	200.4
Purchase commitments	360.8	215.0	162.4	135.3	99.1	773.8	1,746.4
	$ 636.0	$ 448.4	$ 330.8	$ 228.3	$ 312.0	$ 2,538.5	$ 4,494.0

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

At December 31, 2017, the Company had total liabilities of $342.0 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, 2017, 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 deferred credits and other liabilities - other 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 in 2018.

The Company's minimum funding requirements for its defined benefit pension plans for 2018, which are not reflected in the previous table, are $3.1 million. For information on potential contributions above the funding minimum requirements, see item 8 - Note 14.

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.

Critical Accounting Policies Involving Significant Estimates

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

Estimates are used for items such as impairment testing of long-lived assets 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 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, 2017, 2016, and 2015, there were no significant impairment losses recorded. At December 31, 2017, 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 2017. 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.

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 2017.

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 $1.5 million (after tax) for the year ended December 31, 2017.

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

The Company is required to make judgments regarding the potential tax effects of various financial transactions and ongoing operations to estimate the Company's obligation to taxing authorities. These tax obligations include income, real estate and sales/use taxes. Judgments related to income taxes require the recognition in the Company's financial statements of a tax position that is more-likely-than-not to be sustained on audit.

Judgment and estimation is required in developing the provision for income taxes and the reporting of tax-related assets and liabilities and, if necessary, any valuation allowances. The interpretation of tax laws can involve uncertainty, since tax authorities may interpret such laws differently. Actual income tax could vary from estimated amounts and may result in favorable or unfavorable impacts to net income, cash flows, and tax-related assets and liabilities. In addition, the effective tax rate may be affected by other changes including the allocation of property, payroll and revenues between states.

The Company assesses the deferred tax assets for recoverability taking into consideration historical and anticipated earnings levels; the reversal of other existing temporary differences; available net operating losses and tax carryforwards; and available tax planning strategies that could be implemented to realize the deferred tax assets. Based on this assessment, management must evaluate the need for, and amount of, a valuation allowance against the deferred tax assets. As facts and circumstances change, adjustment to the valuation allowance may be required.

Effects of Inflation

Inflation did not have a significant effect on the Company's operations in 2017, 2016 or 2015.

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. For additional information on the Company's long-term debt, see Item 8 - Notes 5 and 6.

At December 31, 2017 and 2016, the Company had no outstanding interest rate hedges.

The following table shows the amount of long-term debt, which excludes unamortized debt issuance costs and discount, and related weighted average interest rates, both by expected maturity dates, as of December 31, 2017.

	2018	2019	2020	2021	2022	Thereafter	Total	Fair Value
				(Dollars in millions)				
Long-term debt:								
Fixed rate	$ 148.5	$ 51.7	$ 15.7	$ .7	$ 147.2	$ 1,211.0	$ 1,574.8	$ 1,680.6
Weighted average interest rate	6.1%	4.3%	5.1%	2.1%	4.5%	4.7%	4.8%	—
Variable rate	—	$ 73.8	$ 57.3	$ 14.6	—	—	$ 145.7	$ 145.7
Weighted average interest rate	—	1.7%	3.7%	1.9%	—	—	2.5%	—

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, 2017. 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, 2017.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2017, has been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report.

/s/ David L. Goodin	/s/ Jason L. Vollmer
David L. Goodin President and Chief Executive Officer	Jason L. Vollmer Vice President, Chief Financial Officer and Treasurer

Report of Independent Registered Public Accounting Firm

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2017 and 2016, the related consolidated statements of income, comprehensive income, equity, and cash flows, for each of the three years in the period ended December 31, 2017, and the related notes and the financial statement schedules listed in the Index at Item 15 (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017 and 2016, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2018, expressed an unqualified opinion on the Company's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits include performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 23, 2018

We have served as the Company's auditor since 2002.

Report of Independent Registered Public Accounting Firm

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

Opinion on Internal Control over Financial Reporting

We have audited the internal control over financial reporting of MDU Resources Group, Inc. and subsidiaries (the "Company") as of December 31, 2017, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on criteria established in *Internal Control-Integrated Framework (2013)* issued by COSO.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2017, of the Company and our report dated February 23, 2018, expressed an unqualified opinion on those consolidated financial statements and financial statement schedules.

Basis for Opinion

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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed 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 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.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 23, 2018

Consolidated Statements of Income

Years ended December 31,		2017		2016		2015
		(In thousands, except per share amounts)				
Operating revenues:						
Electric, natural gas distribution and regulated pipeline and midstream	**$**	**1,244,759**	$	1,141,454	$	1,149,038
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other		**3,198,592**		2,987,374		2,865,014
Total operating revenues		**4,443,351**		4,128,828		4,014,052
Operating expenses:						
Operation and maintenance:						
Electric, natural gas distribution and regulated pipeline and midstream		**323,120**		312,404		278,171
Nonregulated pipeline and midstream, construction materials and contracting, construction services and other		**2,807,682**		2,580,895		2,527,052
Total operation and maintenance		**3,130,802**		2,893,299		2,805,223
Purchased natural gas sold		**430,954**		382,753		450,114
Depreciation, depletion and amortization		**207,486**		216,318		211,747
Taxes, other than income		**166,673**		151,826		140,955
Electric fuel and purchased power		**78,724**		75,512		86,238
Total operating expenses		**4,014,639**		3,719,708		3,694,277
Operating income		**428,712**		409,120		319,775
Other income		**4,103**		4,956		18,457
Interest expense		**82,788**		87,848		91,179
Income before income taxes		**350,027**		326,228		247,053
Income taxes		**65,041**		93,132		70,664
Income from continuing operations		**284,986**		233,096		176,389
Loss from discontinued operations, net of tax (Note 2)		**(3,783)**		(300,354)		(834,080)
Net income (loss)		**281,203**		(67,258)		(657,691)
Loss from discontinued operations attributable to noncontrolling interest (Note 2)		**—**		(131,691)		(35,256)
Loss on redemption of preferred stocks (Note 8)		**600**		—		—
Dividends declared on preferred stocks		**171**		685		685
Earnings (loss) on common stock	**$**	**280,432**	$	63,748	$	(623,120)
Earnings (loss) per common share - basic:						
Earnings before discontinued operations	**$**	**1.46**	$	1.19	$	.90
Discontinued operations attributable to the Company, net of tax		**(.02)**		(.86)		(4.10)
Earnings (loss) per common share - basic	**$**	**1.44**	$	.33	$	(3.20)
Earnings (loss) per common share - diluted:						
Earnings before discontinued operations	**$**	**1.45**	$	1.19	$	.90
Discontinued operations attributable to the Company, net of tax		**(.02)**		(.86)		(4.10)
Earnings (loss) per common share - diluted	**$**	**1.43**	$	.33	$	(3.20)
Weighted average common shares outstanding - basic		**195,304**		195,299		194,928
Weighted average common shares outstanding - diluted		**195,687**		195,618		194,986

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

Consolidated Statements of Comprehensive Income

Years ended December 31,	2017	2016	2015
		(In thousands)	
Net income (loss)	**$ 281,203**	$ (67,258)	$ (657,691)
Other comprehensive income (loss):			
Reclassification adjustment for loss on derivative instruments included in net income (loss), net of tax of $224, $226 and $233 in 2017, 2016 and 2015, respectively	**366**	367	404
Postretirement liability adjustment:			
Postretirement liability losses arising during the period, net of tax of $(1,162), $(836) and $(55) in 2017, 2016 and 2015, respectively	**(1,812)**	(1,470)	(88)
Amortization of postretirement liability losses included in net periodic benefit cost (credit), net of tax of $645, $1,425 and $1,128 in 2017, 2016 and 2015, respectively	**1,013**	2,506	1,794
Reclassification of postretirement liability adjustment (from) to regulatory asset, net of tax of $(876), $0 and $1,416 in 2017, 2016 and 2015, respectively	**(1,143)**	—	2,255
Postretirement liability adjustment	**(1,942)**	1,036	3,961
Foreign currency translation adjustment:			
Foreign currency translation adjustment recognized during the period, net of tax of $(3), $31 and $(105) in 2017, 2016 and 2015, respectively	**(6)**	51	(173)
Reclassification adjustment for loss on foreign currency translation adjustment included in net income (loss), net of tax of $0, $0 and $490 in 2017, 2016 and 2015, respectively	**—**	—	802
Foreign currency translation adjustment	**(6)**	51	629
Net unrealized loss on available-for-sale investments:			
Net unrealized loss on available-for-sale investments arising during the period, net of tax of $(75), $(98) and $(91) in 2017, 2016 and 2015, respectively	**(139)**	(182)	(170)
Reclassification adjustment for loss on available-for-sale investments included in net income (loss), net of tax of $65, $77 and $70 in 2017, 2016 and 2015, respectively	**120**	143	131
Net unrealized loss on available-for-sale investments	**(19)**	(39)	(39)
Other comprehensive income (loss)	**(1,601)**	1,415	4,955
Comprehensive income (loss)	**279,602**	(65,843)	(652,736)
Comprehensive loss from discontinued operations attributable to noncontrolling interest	**—**	(131,691)	(35,256)
Comprehensive income (loss) attributable to common stockholders	**$ 279,602**	$ 65,848	$ (617,480)

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

Consolidated Balance Sheets

December 31,		2017		2016
	(In thousands, except shares and per share amounts)			
Assets				
Current assets:				
Cash and cash equivalents	$	**34,599**	$	46,107
Receivables, net		**727,030**		630,243
Inventories		**226,583**		238,273
Prepayments and other current assets		**81,304**		48,461
Current assets held for sale		**479**		14,391
Total current assets		**1,069,995**		977,475
Investments		**137,613**		125,866
Property, plant and equipment (Note 1)		**6,770,829**		6,510,229
Less accumulated depreciation, depletion and amortization		**2,691,641**		2,578,902
Net property, plant and equipment		**4,079,188**		3,931,327
Deferred charges and other assets:				
Goodwill (Note 3)		**631,791**		631,791
Other intangible assets, net (Note 3)		**3,837**		5,925
Other		**407,850**		415,419
Noncurrent assets held for sale		**4,392**		196,664
Total deferred charges and other assets		**1,047,870**		1,249,799
Total assets	$	**6,334,666**	$	6,284,467
Liabilities and Stockholders' Equity				
Current liabilities:				
Long-term debt due within one year	$	**148,499**	$	43,598
Accounts payable		**312,327**		279,962
Taxes payable		**42,537**		48,164
Dividends payable		**38,573**		37,767
Accrued compensation		**72,919**		65,867
Other accrued liabilities		**186,010**		184,377
Current liabilities held for sale		**11,993**		9,924
Total current liabilities		**812,858**		669,659
Long-term debt (Note 6)		**1,566,354**		1,746,561
Deferred credits and other liabilities:				
Deferred income taxes		**347,271**		668,226
Other		**1,179,140**		883,777
Total deferred credits and other liabilities		**1,526,411**		1,552,003
Commitments and contingencies (Notes 14, 16 and 17)				
Stockholders' equity:				
Preferred stocks (Note 8)		**—**		15,000
Common stockholders' equity:				
Common stock (Note 9) Authorized - 500,000,000 shares, $1.00 par value Issued - 195,843,297 shares in 2017 and 2016		**195,843**		195,843
Other paid-in capital		**1,233,412**		1,232,478
Retained earnings		**1,040,748**		912,282
Accumulated other comprehensive loss		**(37,334)**		(35,733)
Treasury stock at cost - 538,921 shares		**(3,626)**		(3,626)
Total common stockholders' equity		**2,429,043**		2,301,244
Total stockholders' equity		**2,429,043**		2,316,244
Total liabilities and stockholders' equity	$	**6,334,666**	$	6,284,467

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

Consolidated Statements of Equity

Years ended December 31, 2017, 2016 and 2015

	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, 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
Net income	—	—	—	—	—	281,203	—	—	—	—	281,203
Other comprehensive loss	—	—	—	—	—	—	(1,601)	—	—	—	(1,601)
Dividends declared on preferred stocks	—	—	—	—	—	(171)	—	—	—	—	(171)
Dividends declared on common stock	—	—	—	—	—	(151,966)	—	—	—	—	(151,966)
Stock-based compensation	—	—	—	—	3,375	—	—	—	—	—	3,375
Repurchase of common stock	—	—	—	—	—	—	—	(64,384)	(1,684)	—	(1,684)
Issuance of common stock upon vesting of stock-based compensation, net of shares used for tax withholdings	—	—	—	—	(2,441)	—	—	64,384	1,684	—	(757)
Redemption of preferred stock	(150,000)	(15,000)	—	—	—	(600)	—	—	—	—	(15,600)
Balance at December 31, 2017	**—**	**$ —**	**195,843,297**	**$ 195,843**	**$ 1,233,412**	**$ 1,040,748**	**$ (37,334)**	**(538,921)**	**$ (3,626)**	**$ —**	**$ 2,429,043**

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

Consolidated Statements of Cash Flows

Years ended December 31,	2017	2016	2015
		(In thousands)	
Operating activities:			
Net income (loss)	**$ 281,203**	$ (67,258)	$ (657,691)
Loss from discontinued operations, net of tax	**(3,783)**	(300,354)	(834,080)
Income from continuing operations	**284,986**	233,096	176,389
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	**207,486**	216,318	211,747
Deferred income taxes	**(25,423)**	(2,049)	(25,356)
Changes in current assets and liabilities, net of acquisitions:			
Receivables	**(108,255)**	(25,641)	4,704
Inventories	**9,135**	2,433	2,265
Other current assets	**(30,588)**	(17,925)	60,182
Accounts payable	**26,013**	7,039	37,224
Other current liabilities	**4,648**	36,146	6,864
Other noncurrent changes	**(18,790)**	(26,459)	(10,240)
Net cash provided by continuing operations	**349,212**	422,958	463,779
Net cash provided by discontinued operations	**98,799**	39,251	198,053
Net cash provided by operating activities	**448,011**	462,209	661,832
Investing activities:			
Capital expenditures	**(341,382)**	(388,183)	(536,832)
Net proceeds from sale or disposition of property and other	**126,588**	44,826	54,569
Investments	**(1,608)**	(1,396)	1,515
Net cash used in continuing operations	**(216,402)**	(344,753)	(480,748)
Net cash provided by discontinued operations	**2,234**	39,658	98,295
Net cash used in investing activities	**(214,168)**	(305,095)	(382,453)
Financing activities:			
Issuance of long-term debt	**140,812**	309,064	345,920
Repayment of long-term debt	**(217,394)**	(315,647)	(566,498)
Proceeds from issuance of common stock	**—**	—	21,898
Dividends paid	**(150,727)**	(147,156)	(142,835)
Redemption of preferred stock	**(15,600)**	—	—
Repurchase of common stock	**(1,684)**	—	—
Tax withholding on stock-based compensation	**(757)**	(323)	—
Net cash used in continuing operations	**(245,350)**	(154,062)	(341,515)
Net cash provided by (used in) discontinued operations	**—**	(40,852)	85,785
Net cash used in financing activities	**(245,350)**	(194,914)	(255,730)
Effect of exchange rate changes on cash and cash equivalents	**(1)**	4	(225)
Increase (decrease) in cash and cash equivalents	**(11,508)**	(37,796)	23,424
Cash and cash equivalents - beginning of year	**46,107**	83,903	60,479
Cash and cash equivalents - end of year	**$ 34,599**	$ 46,107	$ 83,903

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, 2017, up to the date of issuance of these consolidated financial statements.

On December 22, 2017, President Trump signed into law the TCJA which includes lower corporate tax rates, repealing the domestic production deduction, disallowance of immediate expensing for regulated utility property and modifying or repealing many other business deductions and credits. In accordance with the accounting guidance on accounting for income taxes, entities must account for the effects of the change in tax laws or rates in the period of enactment. In the fourth quarter of 2017, the period of enactment, the Company performed a one-time revaluation of the net deferred tax liabilities to account for the reduction in the corporate tax rate from 35 percent to 21 percent effective January 1, 2018. For more information on the impacts of the TCJA on the year ended December 31, 2017, see Notes 4 and 11. The Company is currently reviewing the components of the TCJA and evaluating the impact on the Company's consolidated financial statements and related disclosures for 2018 and thereafter.

As part of the Company's strategic plan to grow its capital investments while focusing on creating a greater long-term value and reducing the Company's risk by decreasing exposure to commodity prices, the Company completed the sales of substantially all of Fidelity's oil and and natural gas assets between October 2015 and April 2016 and Dakota Prairie Refining on June 27, 2016.

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 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. 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 mo re information, see Percentage-of-completion method in this note. The total balance of receivables past due 90 days or more was $34.7 million and $29.2 million at December 31, 2017 and 2016, 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, 2017 and 2016, was $8.1 million and $10.5 million, respectively.

Inventories and natural gas in storage

Natural gas in storage for the Company's regulated operations is generally carried at lower of cost or net realizable value, or cost using the last-in, first-out method. All other inventories are stated at the lower of cost or net realizable 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:

	2017	2016
	(In thousands)	
Aggregates held for resale	**$ 115,268**	$ 115,471
Asphalt oil	**30,360**	29,103
Natural gas in storage (current)	**20,950**	25,761
Materials and supplies	**18,650**	18,372
Merchandise for resale	**14,905**	16,437
Other	**26,450**	33,129
Total	**$ 226,583**	$ 238,273

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 $49.3 million and $49.5 million at December 31, 2017 and 2016, 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:

	2017	2016	2015
		(In thousands)	
Interest capitalized	**$ —**	$ —	$ 4,381
AFUDC - borrowed	**$ 966**	$ 914	$ 4,907
AFUDC - equity	**$ 909**	$ 565	$ 7,971

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 deferred credits and other liabilities - other.

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

	2017	2016	Weighted Average Depreciable Life in Years
	(Dollars in thousands, where applicable)		
Regulated:			
Electric:			
Generation	$ 1,034,765	$ 1,036,373	39
Distribution	415,543	398,382	44
Transmission	296,941	284,048	57
Construction in progress	117,906	62,212	—
Other	117,109	107,598	15
Natural gas distribution:			
Distribution	1,831,795	1,718,633	47
Construction in progress	19,823	19,934	—
Other	468,227	440,846	18
Pipeline and midstream:			
Transmission	516,932	490,143	53
Gathering	37,837	37,831	20
Storage	45,629	45,350	62
Construction in progress	17,488	16,507	—
Other	41,054	40,873	33
Nonregulated:			
Pipeline and midstream:			
Gathering and processing	31,678	31,682	19
Construction in progress	17	13	—
Other	9,649	9,800	10
Construction materials and contracting:			
Land	95,745	94,625	—
Buildings and improvements	102,435	102,347	20
Machinery, vehicles and equipment	947,979	930,471	12
Construction in progress	7,750	16,181	—
Aggregate reserves	406,139	405,751	*
Construction services:			
Land	5,216	5,346	—
Buildings and improvements	27,351	26,693	25
Machinery, vehicles and equipment	137,924	132,217	6
Other	6,774	7,105	4
Other:			
Land	2,837	2,837	—
Other	28,286	46,431	19
Less accumulated depreciation, depletion and amortization	2,691,641	2,578,902	
Net property, plant and equipment	$ 4,079,188	$ 3,931,327	

* 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 or 2017, 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, 2017, 2016 and 2015, there were no significant impairment losses recorded. At December 31, 2017, 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 2017. 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.

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 $112.7 million and $117.7 million at December 31, 2017 and 2016, 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:

	2017	2016
	(In thousands)	
Costs and estimated earnings in excess of billings on uncompleted contracts	$ 109,541	$ 64,558
Billings in excess of costs and estimated earnings on uncompleted contracts	$ 84,123	$ 64,832

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

	2017	2016
	(In thousands)	
Short-term retainage*	$ 57,134	$ 45,109
Long-term retainage**	1,410	1,506
Total retainage	$ 58,544	$ 46,615

* 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 $28.5 million and $25.6 million at December 31, 2017 and 2016, respectively, which is included in other accrued liabilities. Natural gas costs recoverable through rate adjustments were $14.5 million and $2.2 million at December 31, 2017 and 2016, respectively, which is included in prepayments and other current assets.

Stock-based compensation

The Company records the compensation expense for performance share awards using an estimated forfeiture rate. The estimated forfeiture rate is calculated based on an average of actual historical forfeitures. The Company also preforms an analysis of any known factors at the time of the calculation to identify any necessary adjustments to the average historical forfeiture rate. At the time actual forfeitures become more than estimated forfeitures, the Company records compensation expense using actual forfeitures.

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 by using enacted tax rates in effect for the year in which the differences are expected to reverse. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date. 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.

The Company records uncertain tax positions in accordance with accounting guidance on accounting for income taxes on the basis of a two-step process in which (1) the Company determines whether it is more-likely-than-not that the tax position will be sustained on the basis of the technical merits of the position and (2) for those tax positions that meet the more-likely than-not recognition threshold, the Company recognizes the largest amount of the tax benefit that is more than 50 percent likely to be realized upon ultimate settlement with the related tax authority. Tax positions that do not meet the more-likely-than-not criteria are reflected as a tax liability. 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 nonvested performance share awards. Common stock outstanding includes issued shares less shares held in treasury. Earnings (loss) on common stock 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:

	2017	2016	2015
		(In thousands)	
Weighted average common shares outstanding - basic	**195,304**	195,299	194,928
Effect of dilutive performance share awards	**383**	319	58
Weighted average common shares outstanding - diluted	**195,687**	195,618	194,986
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 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

Recently adopted accounting standards

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. The Company adopted the guidance on January 1, 2017, on a prospective basis. The guidance did not have a material effect on the Company's results of operations, financial position, cash flows or 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 affects the income tax consequences, classification of awards as either equity or liabilities, classification on the statement of cash flows and calculation of dilutive shares. 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 adoption of the guidance impacted the Consolidated Statement of Income and the Consolidated Balance Sheet in the first quarter of 2017 due to the taxes related to the stock-based compensation award that vested in February 2017 being recognized as income tax expense as compared to a reduction to additional paid-in capital under the previous guidance. Adoption of the guidance also increased the number of shares included in the diluted earnings per share calculation due to the exclusion of tax benefits in the incremental shares calculation. The change in the weighted average common shares outstanding - diluted did not result in a material effect on the earnings per common share - diluted.

Recently issued accounting standards not yet adopted

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. In August 2015, the FASB issued guidance deferring the effective date of the revenue guidance and allowing entities to early adopt. With this decision, the guidance was effective for the Company on January 1, 2018. Entities had the option of using either a full retrospective or modified retrospective approach to adopting the guidance. Under the modified retrospective approach, an entity recognizes the cumulative effect of initially applying the guidance with an adjustment to the opening balance of retained earnings in the period of adoption.

The Company adopted the guidance on January 1, 2018, using the modified retrospective approach. The Company has substantially completed the evaluation of contracts and methods of revenue recognition under the previous accounting guidance and has not identified any material cumulative effect adjustments to be made to retained earnings. In addition, the Company will have expanded revenue disclosures, both quantitatively and qualitatively, related to the nature, amount, timing and uncertainty of revenue and cash flows arising from contracts with customers in the first quarter of 2018. The Company has reviewed substantially all of its revenue streams to evaluate the impact of this guidance and does not anticipate a significant change in the timing of revenue recognition, results of operations, financial position or cash flows. The Company reviewed its internal controls related to revenue recognition and disclosures and concluded that the guidance impacts certain business processes and controls. As such, the Company has developed modifications to its internal controls for certain topics under the guidance as they apply to the Company and such modifications were not deemed to be significant.

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 was effective for the Company on January 1, 2018. The guidance was to be applied using a modified retrospective approach with the exception of equity securities without readily determinable fair values which should be applied prospectively. The Company continues to evaluate the effects the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures and does not anticipate a material impact.

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. The Company adopted the guidance on January 1, 2018, on a prospective basis. The Company does not anticipate the guidance to have a material effect on its future results of operations, financial position, 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 also affects other aspects of accounting, such as determining reporting units for goodwill testing and whether an entity has acquired or sold a business. The Company adopted the guidance on January 1, 2018, on a prospective basis. The Company does not anticipate the guidance to have a material effect on its future results of operations, financial position, cash flows and disclosures.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost In March 2017, the FASB issued guidance to improve the presentation of net periodic pension cost and net periodic postretirement benefit cost. The guidance requires the service cost component to be presented in the income statement in the same line item or items as other compensation costs arising from services performed during the period. Other components of net benefit costs shall be presented in the income statement separately from the service cost component and outside a subtotal of income from operations. The guidance also allows only the service cost component to be eligible for capitalization. The guidance was effective for the Company on January 1, 2018, including interim periods, on a retrospective basis for all periods presented with the exception of the capitalization of the service cost component which was adopted on a prospective basis.

The Company will reclassify all components of net periodic benefit costs, except for the service cost component, from operating expenses to other income (expense) on the Consolidated Statements of Income for all years presented prior to January 1, 2018, beginning in the first quarter of 2018, with no impact to earnings. The guidance will not have a material impact on the Company's disclosures or cash flows.

Under FERC regulation, all components of net periodic benefit costs are currently eligible for capitalization. The Company's electric and natural gas distribution businesses have elected to continue to defer all components of net periodic benefit costs as regulatory assets or liabilities.

Leases In February 2016, the FASB issued guidance regarding leases. The guidance requires lessees to recognize a lease liability and a right-of-use asset on the balance sheet for operating and financing leases with terms of more than 12 months. The guidance remains largely the same for lessors, although some changes were made to better align lessor accounting with the new lessee accounting and to align with the revenue recognition standard. The guidance also requires additional disclosures, both quantitative and qualitative, related to operating and finance leases for the lessee and sales-type, direct financing and operating leases for the lessor. This guidance will be effective for the Company on January 1, 2019, and should be applied using a retrospective approach with early adoption permitted. The Company continues to evaluate the potential impact the adoption of the new guidance will have on its results of operations, financial position, cash flows and disclosures. The Company is planning to adopt the standard on January 1, 2019, utilizing the practical expedient that allows the Company to not reassess whether an expired or existing contract contains a lease, the classification of leases or initial direct costs.

In January 2018, the FASB issued a practical expedient for land easements under the new lease guidance. The practical expedient permits an entity to elect the option to not evaluate land easements under the new guidance if they existed or expired before the adoption of the new lease guidance and were not previously accounted for as leases under the previous lease guidance. Once an entity adopts the new guidance, the entity should apply the new guidance on a prospective basis to all new or modified land easements. The Company is currently evaluating the impact of the practical expedient.

On January 5, 2018, the FASB issued a proposed accounting standard update to the guidance that would allow an entity the option to adopt the guidance on a modified retrospective basis. Under the modified retrospective approach, an entity would recognize a cumulative effect adjustment of initially applying the guidance to the opening balance of retained earnings in the period of adoption. The Company is monitoring the status of the proposal.

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.

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income In February 2018, the FASB issued guidance that allows an entity to reclassify the stranded tax effects resulting from the newly enacted federal corporate income tax rate from accumulated other comprehensive income (loss) to retained earnings. The guidance is effective for the Company on January 1, 2019, including interim periods, with early adoption permitted. The guidance can be applied using one of two methods. One method is to record the reclassification of the stranded income taxes at the beginning of the period of adoption. The other method is to apply the guidance retrospectively to each period in which the income tax effects of the TCJA are recognized in accumulated other comprehensive income (loss). The Company is evaluating adoption of the guidance in the first quarter of 2018. At December 31, 2017, the Company had $7.7 million of stranded tax effects in the accumulated other comprehensive loss balance.

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, 2017, 2016 and 2015, 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, 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)
Other comprehensive loss before reclassifications	—	(1,812)	(6)	(139)	(1,957)
Amounts reclassified from accumulated other comprehensive loss	366	1,013	—	120	1,499
Amounts reclassified to accumulated other comprehensive loss from a regulatory asset	—	(1,143)	—	—	(1,143)
Net current-period other comprehensive income (loss)	366	(1,942)	(6)	(19)	(1,601)
Balance at December 31, 2017	**$ (1,934)**	**$ (35,163)**	**$ (155)**	**$ (82)**	**$ (37,334)**

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

	2017	2016	Location on Consolidated Statements of Income
	(In thousands)		
Reclassification adjustment for loss on derivative instruments included in net income (loss):			
Interest rate derivative instruments	**$ (590)**	$ (593)	Interest expense
	224	226	Income taxes
	(366)	(367)	
Amortization of postretirement liability losses included in net periodic benefit cost (credit)	**(1,658)**	(3,931)	(a)
	645	1,425	Income taxes
	(1,013)	(2,506)	
Reclassification adjustment for loss on available-for-sale investments included in net income (loss)	**(185)**	(220)	Other income
	65	77	Income taxes
	(120)	(143)	
Total reclassifications	**$ (1,499)**	$ (3,016)	

(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 of Pronghorn were classified as held for sale in the fourth quarter of 2016. Pronghorn's results of operations for 2016 were included in the pipeline and midstream segment.

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 Andeavor Field Services LLC. The transaction closed on January 1, 2017, which generated approximately $100 million of proceeds for the Company. The sale of Pronghorn further reduced the Company's risk exposure to commodity prices.

The carrying amounts of the major classes of assets 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 Andeavor Field Services LLC. 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 have 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 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. 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 reduced the Company's risk by decreasing exposure to commodity prices.

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 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:

	2017		2016
	(In thousands)		
Assets			
Current assets:			
Income taxes receivable	$ 1,778		$ 13,987
Total current assets held for sale	1,778		13,987
Total assets held for sale	$ 1,778	(a)	$ 13,987
Liabilities			
Current liabilities:			
Accounts payable	$ —		$ 7,425
Total current liabilities held for sale	—		7,425
Noncurrent liabilities:			
Deferred income taxes (b)	37		14
Total noncurrent liabilities held for sale	37		14
Total liabilities held for sale	$ 37		$ 7,439

(a) On the Company's Consolidated Balance Sheets, these amounts were reclassified to current income taxes payable and are reflected in current liabilities held for sale.
(b) 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 retained certain liabilities of Dakota Prairie Refining which were reflected in current liabilities held for sale on the Consolidated Balance Sheet at December 31, 2016. In the first quarter of 2017, the Company recorded a reversal of a previously accrued liability of $7.0 million ($4.3 million after tax) due to the resolution of a legal matter. As of December 31, 2017, Dakota Prairie Refining had not incurred any material exit and disposal costs, and does not expect to incur any material exit and disposal costs.

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.

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

		2017		2016	
		(In thousands)			
Assets					
Current assets:					
Receivables, net	$	479	$	355	
Total current assets held for sale		479		355	
Noncurrent assets:					
Net property, plant and equipment		1,631		5,507	
Deferred income taxes		2,637		91,098	
Other		161		161	
Less allowance for impairment of assets held for sale		—		938	
Total noncurrent assets held for sale		4,429		95,828	
Total assets held for sale	$	4,908	$	96,183	
Liabilities					
Current liabilities:					
Accounts payable	$	30	$	141	
Taxes payable		10,857		19	(a)
Other accrued liabilities		2,884		2,358	
Total current liabilities held for sale		13,771		2,518	
Total liabilities held for sale	$	13,771	$	2,518	

(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, 2017 and 2016, the Company’s deferred tax assets included in assets held for sale were largely comprised of $2.6 million and $89.3 million, respectively, of federal and state net operating loss carryforwards. The Company realized substantially all of the outstanding net operating loss carryforwards in 2017.

The Company had federal income tax net operating loss carryforwards of $4.4 million and $297.2 million at December 31, 2017 and 2016, respectively. At December 31, 2017 and 2016, the Company had various state income tax net operating loss carryforwards of $13.8 million and $189.1 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 $349,000 and $500,000 have been provided in 2017 and 2016, respectively.

The Company performed a fair value assessment of the assets and liabilities classified as held for sale. 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 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 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 is 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 in 2016. 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 loss recognized in discontinued operations, before tax, was $18.3 million in the year ended December 31, 2015.

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

	2017	2016	2015
		(In thousands)	
Operating revenues	**$ 465**	$ 123,024	$ 363,115
Operating expenses	**(4,607)**	513,813	1,666,941
Operating income (loss)	**5,072**	(390,789)	(1,303,826)
Other income (expense)	**(13)**	306	3,149
Interest expense	**250**	1,753	2,124
Income (loss) from discontinued operations before income taxes	**4,809**	(392,236)	(1,302,801)
Income taxes*	**8,592**	(91,882)	(468,721)
Loss from discontinued operations	**(3,783)**	(300,354)	(834,080)
Loss from discontinued operations attributable to noncontrolling interest	**—**	(131,691)	(35,256)
Loss from discontinued operations attributable to the Company	**$ (3,783)**	$ (168,663)	$ (798,824)

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

The pretax income (loss) from discontinued operations attributable to the Company, related to the operations of and activity associated with Dakota Prairie Refining, was $6.9 million, $(253.5) million and $(31.5) million for the years ended December 31, 2017, 2016 and 2015, respectively.

Note 3 - Goodwill and Other Intangible Assets

The changes in the carrying amount of goodwill for the year ended December 31, 2017, were as follows:

		Balance at January 1, 2017		Goodwill Acquired During the Year		Balance at December 31, 2017
				(In thousands)		
Natural gas distribution	$	345,736	$	—	$	345,736
Construction materials and contracting		176,290		—		176,290
Construction services		109,765		—		109,765
Total	$	631,791	$	—	$	631,791

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		Less 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.

Other amortizable intangible assets at December 31 were as follows:

		2017		2016
		(In thousands)		
Customer relationships	**$**	**15,248**	$	17,145
Less accumulated amortization		**13,382**		13,917
		1,866		3,228
Noncompete agreements		**2,430**		2,430
Less accumulated amortization		**1,805**		1,658
		625		772
Other		**6,990**		7,768
Less accumulated amortization		**5,644**		5,843
		1,346		1,925
Total	**$**	**3,837**	$	5,925

Amortization expense for amortizable intangible assets for the years ended December 31, 2017, 2016 and 2015, was $2.0 million, $2.5 million and $2.5 million, respectively. Estimated amortization expense for intangible assets is $1.3 million in 2018, $1.0 million in 2019, $500,000 in 2020, $300,000 in 2021, $200,000 in 2022 and $500,000 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 *	2017	2016
		(In thousands)	
Regulatory assets:			
Pension and postretirement benefits (a)	(e)	$ 163,896	$ 176,025
Taxes recoverable from customers (a)	Over plant lives	12,073	28,278
Manufactured gas plant sites remediation (a)	-	18,213	18,259
Asset retirement obligations (a)	Over plant lives	56,078	42,580
Natural gas costs recoverable through rate adjustments (b)	Up to 1 year	14,465	2,242
Long-term debt refinancing costs (a)	Up to 20 years	5,563	6,248
Costs related to identifying generation development (a)	Up to 9 years	2,960	3,407
Other (a) (b)	Up to 20 years	27,715	30,281
Total regulatory assets		300,963	307,320
Regulatory liabilities:			
Plant removal and decommissioning costs (c)		176,190	176,972
Taxes refundable to customers (c)		279,668	11,010
Pension and postretirement benefits (c)		11,056	9,099
Natural gas costs refundable through rate adjustments (d)		28,514	25,580
Other (c) (d)		23,870	19,191
Total regulatory liabilities		519,298	241,852
Net regulatory position		$ (218,335)	$ 65,468

* 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, 2017 and 2016, approximately $269.1 million and $255.4 million, respectively, of regulatory assets were not earning a rate of return.

In the fourth quarter of 2017, the Company performed a one-time revaluation of the Company's regulated deferred tax assets and liabilities for the reduction of the corporate tax rate from 35 percent to 21 percent effective January 1, 2018, as identified in the TCJA. The revaluation of the Company's regulatory deferred tax assets and liabilities are being deferred as the Company works with the various regulators on a plan for amounts expected to be returned to customers, as discussed in Note 16. In the fourth quarter of 2017, the revaluation of the deferred tax assets and liabilities resulted in a decrease of $15.5 million in taxes recoverable from customers and an increase of $270.0 million in taxes refundable to customers. These regulatory amounts are expected to generally be refunded over the remaining life of the related assets as prescribed in the TCJA. The approved regulatory treatment of the impacts of the TCJA by the various regulators may affect the analyses performed.

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 $77.4 million and $70.9 million at December 31, 2017 and 2016, respectively, were classified as investments on the Consolidated Balance Sheets. The net unrealized gains on these investments for the years ended December 31, 2017, 2016 and 2015, were $9.3 million, $3.4 million and

$1.7 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, 2017	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
		(In thousands)		
Mortgage-backed securities	$ 10,342	$ 4	$ 129	$ 10,217
U.S. Treasury securities	205	—	1	204
Total	$ 10,547	$ 4	$ 130	$ 10,421

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

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, 2017 and 2016, there were no transfers between Levels 1 and 2.

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

	Fair Value Measurements at December 31, 2017, 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, 2017
	(In thousands)			
Assets:				
Money market funds	$ —	$ 6,965	$ —	$ 6,965
Insurance contract*	—	77,388	—	77,388
Available-for-sale securities:				
Mortgage-backed securities	—	10,217	—	10,217
U.S. Treasury securities	—	204	—	204
Total assets measured at fair value	$ —	$ 94,774	$ —	$ 94,774

* The insurance contract invests approximately 49 percent in fixed-income investments, 23 percent in common stock of large-cap companies, 14 percent in common stock of mid-cap companies, 11 percent in common stock of small-cap companies, 2 percent in target date investments and 1 percent in cash equivalents.

	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.

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:

	2017		2016	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
		(In thousands)		
Long-term debt	**$ 1,714,853**	**$ 1,826,256**	$ 1,790,159	$ 1,841,885

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, 2017	Amount Outstanding at December 31, 2016	Letters of Credit at December 31, 2017	Expiration Date
				(In millions)		
MDU Resources Group, Inc.	Commercial paper/Revolving credit agreement (a)	$ 175.0	$ 73.8 (b)	$ 111.0 (b)	$ —	5/8/19
Cascade Natural Gas Corporation	Revolving credit agreement	$ 75.0 (c)	$ 17.3	$ —	$ 2.2 (d)	4/24/20
Intermountain Gas Company	Revolving credit agreement	$ 85.0 (e)	$ 40.0	$ 20.9	$ —	4/24/20
Centennial Energy Holdings, Inc.	Commercial paper/Revolving credit agreement (f)	$ 500.0	$ 14.6 (b)	$ 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 revolving credit agreement.
(b) Amount outstanding under commercial paper program.
(c) Certain provisions allow for increased borrowings, up to a maximum of $100.0 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 $110.0 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 revolving 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.

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.

On April 25, 2017, Cascade amended its revolving credit agreement to increase the borrowing limit from $50.0 million to $75.0 million and extend the termination date from July 9, 2018 to April 24, 2020. 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.

On April 25, 2017, Intermountain amended its revolving credit agreement to increase the borrowing limit from $65.0 million to $85.0 million and extend the termination date from July 13, 2018 to April 24, 2020. 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.

Centennial Energy Holdings, Inc. 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. WBI Energy Transmission has a $200.0 million uncommitted note purchase and private shelf agreement with an expiration date of May 16, 2019. WBI Energy Transmission had $100.0 million of notes outstanding at December 31, 2017, 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. On December 22, 2017, WBI Energy Transmission contracted to issue an additional $40.0 million under the private shelf agreement at an interest rate of 4.18 percent on June 15, 2018.

Long-term Debt Outstanding Long-term debt outstanding was as follows:

	Weighed Average Interest Rate at December 31, 2017		December 31, 2017		December 31, 2016
			(In thousands)		
Senior Notes due on dates ranging from June 19, 2018 to January 15, 2055	**4.71%**	**$**	**1,499,916**	$	1,437,831
Commercial paper supported by revolving credit agreements	**1.72%**		**88,350**		262,000
Medium-Term Notes due on dates ranging from September 1, 2020 to March 16, 2029	**6.68%**		**50,000**		50,000
Other notes due on dates ranging from July 1, 2019 to November 30, 2038	**5.24%**		**24,982**		24,471
Credit agreements due on April 24, 2020	**3.71%**		**57,300**		21,793
Less unamortized debt issuance costs			**5,694**		5,832
Less discount			**1**		104
Total long-term debt			**1,714,853**		1,790,159
Less current maturities			**148,499**		43,598
Net long-term debt		**$**	**1,566,354**	$	1,746,561

Schedule of Debt Maturities Long-term debt maturities, which excludes unamortized debt issuance costs and discount, for the five years and thereafter following December 31, 2017, were as follows:

	2018	2019	2020	2021	2022	Thereafter
			(In thousands)			
Long-term debt maturities	$ 148,499	$ 125,504	$ 73,012	$ 15,312	$ 147,214	$ 1,211,007

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:

		2017		2016
		(In thousands)		
Balance at beginning of year	**$**	**314,970**	$	242,224
Liabilities incurred		**15,110**		15,114
Liabilities settled		**(4,981)**		(4,338)
Accretion expense*		**16,839**		13,918
Revisions in estimates		**31**		48,052
Balance at end of year	**$**	**341,969**	$	314,970

* Includes $15.6 million and $12.7 million in 2017 and 2016, respectively, related to regulatory assets.

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 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:

	2017	2016
	(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
4.70% Series - 50,000 shares	**—**	5,000
Total preferred stocks	**$ —**	$ 15,000

For the years 2016 and 2015, dividends declared on the 4.50% Series and 4.70% Series preferred stocks were $4.50 and $4.70 per share, respectively. On April 1, 2017, the Company redeemed all outstanding 4.50% Series and 4.70% Series preferred stocks at $105 per share and $102 per share, respectively, for a repurchase price of approximately $15.6 million and $300,000 of redeemable preferred stock classified as long-term debt.

Note 9 - Common Stock

For the years 2017, 2016 and 2015, dividends declared on common stock were $.7750, $.7550 and $.7350 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 2015 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 2017, the K-Plan purchased shares of common stock on the open market. At December 31, 2017, 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 were 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 has regulatory limitations on the amount of dividends it 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, 2017. 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 $384 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, 2017. 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 other stock awards. As of December 31, 2017, there were 5.1 million remaining shares available to grant under these plans. The Company generally purchases shares on the open market for non-employee director stock awards. The Company purchased shares on the open market for the employee performance shares that vested in 2017. The Company anticipates future employee performance share awards will continue to be satisfied by purchasing shares on the open market.

Total stock-based compensation expense (after tax) was $2.7 million, $3.3 million and $2.9 million in 2017, 2016 and 2015, respectively.

As of December 31, 2017, total remaining unrecognized compensation expense related to stock-based compensation was approximately $4.8 million (before income taxes) which will be amortized over a weighted average period of 1.5 years.

Stock awards

Non-employee directors receive shares of common stock in addition to and in lieu of cash payment for directors' fees. Shares of common stock were issued under the non-employee director stock compensation plan or the non-employee director long-term incentive compensation plan. There were 40,572 shares with a fair value of $1.1 million, 37,218 shares with a fair value of $1.1 million and 58,181 shares with a fair value of $1.1 million issued under these plans during the years ended December 31, 2017, 2016 and 2015, 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, 2017, were as follows:

Grant Date	Performance Period	Target Grant of Shares
February 2016	2016-2018	258,825
March 2016	2016-2018	2,151
February 2017	2017-2019	164,558

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 2017, 2016 and 2015 were:

	2017			2016			2015		
Weighted average grant-date fair value			**$24.31**			$14.60			$18.98
Blended volatility range	**22.70%**	**–**	**25.56%**	29.25%	–	32.51%	22.86%	–	24.61%
Risk-free interest rate range	**.69%**	**–**	**1.61%**	.47%	–	.92%	.05%	–	1.07%
Weighted average discounted dividends per share			**$1.70**			$1.56			$1.57

The fair value of the performance shares that vested during the years ended December 31, 2017 and 2016, was $9.6 million and $953,000, 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, 2017, was as follows:

	Number of Shares		Weighted Average Grant-Date Fair Value
Nonvested at beginning of period	664,188	$	21.47
Granted	203,646		24.31
Additional performance shares earned	81,643		19.22
Less:			
Vested	360,319		24.88
Forfeited	163,624		24.46
Nonvested at end of period	425,534	$	18.35

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:

	2017	2016	2015
		(In thousands)	
United States	$ **350,064**	$ 326,252	$ 248,379
Foreign	**(37)**	(24)	(1,326)
Income before income taxes from continuing operations	$ **350,027**	$ 326,228	$ 247,053

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

	2017	2016	2015
		(In thousands)	
Current:			
Federal	$ **74,272**	$ 81,989	$ 85,897
State	**16,192**	13,190	10,093
Foreign	**—**	2	30
	90,464	95,181	96,020
Deferred:			
Income taxes:			
Federal	**(24,497)**	(2,102)	(19,632)
State	**(864)**	1,184	(5,304)
Investment tax credit - net	**(62)**	(1,131)	(420)
	(25,423)	(2,049)	(25,356)
Total income tax expense	$ **65,041**	$ 93,132	$ 70,664

In accordance with the accounting guidance on accounting for income taxes, the tax effects of the change in tax laws or rates are to be recorded in the period of enactment. The TCJA was enacted on December 22, 2017, as discussed in Note 1. Therefore, the reduction in the corporate tax rate from 35 percent to 21 percent required the Company to prepare a one-time revaluation of the Company's deferred tax assets and liabilities in the fourth quarter of 2017, the period of enactment. The deferred taxes were revalued at the new tax rate because deferred taxes should reflect what the Company expects to pay or receive in future periods under the applicable tax rate. As a result of the revaluation, the Company reduced the value of these assets and liabilities and recorded a tax benefit from continuing operations of $39.5 million on the Consolidated Statements of Income for the year ended December 31, 2017. Included in the tax benefit from continuing operations was income tax expense of $7.7 million related to amounts in accumulated other comprehensive loss and $1.0 million related to the Company's assets held for sale.

The Company's regulated operations prepared a one-time revaluation of the Company's regulatory deferred tax assets and liabilities in the fourth quarter of 2017 related to the enactment of the TCJA. The revaluation is being deferred under regulatory accounting as the Company works with the various regulators on a plan for amounts expected to be returned to customers, as discussed in Notes 4 and 16. The revaluation of the deferred tax assets and liabilities resulted in a net decrease of $285.5 million in the fourth quarter of 2017. These regulatory amounts are expected to generally be refunded over the remaining life of the related assets as prescribed in the TCJA. The approved regulatory treatment of the impacts of the TCJA by the various regulators may affect the analyses performed.

The changes included in the TCJA are broad and complex. While the Company was able to make reasonable estimates of the impact of the reduction in corporate tax rate on the Company's net deferred tax liabilities, it may be affected by other analyses related to the TCJA, including, but not limited to, the state tax effect of adjustments to federal temporary differences and the calculation of deemed repatriation of deferred foreign income. The final transition impacts of the TCJA may differ from amounts disclosed, possibly materially, due to, among other things, changes in interpretations, legislative action to address questions, changes in accounting standards for income taxes or related interpretations, or updates or changes to estimates the Company has utilized to calculate the transition impacts. The SEC has issued rules that would allow for a measurement period of up to one year after the enactment date of the TCJA to finalize the recording of the related tax impacts. The Company currently anticipates finalizing and recording any resulting adjustments by December 31, 2018, which will be included in income from continuing operations.

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

	2017	2016
	(In thousands)	
Deferred tax assets:		
Postretirement	$ 55,736	$ 87,872
Compensation-related	16,298	44,995
Alternative minimum tax credit carryforward	37,683	29,338
Federal renewable energy credit	19,367	16,944
Customer advances	8,712	13,524
Legal and environmental contingencies	7,363	9,895
Asset retirement obligations	6,380	8,867
Other	35,738	46,957
Total deferred tax assets	187,277	258,392
Deferred tax liabilities:		
Depreciation and basis differences on property, plant and equipment	429,577	774,838
Postretirement	43,505	70,670
Intangible asset amortization	16,979	26,413
Other	32,591	45,580
Total deferred tax liabilities	522,652	917,501
Valuation allowance	11,896	9,117
Net deferred income tax liability	$ 347,271	$ 668,226

As of December 31, 2017 and 2016, the Company had various state income tax net operating loss carryforwards of $130.1 million and $114.7 million, respectively, and federal and state income tax credit carryforwards, excluding alternative minimum tax credit carryforwards, of $52.5 million and $43.3 million, respectively. Included in the state credits are various regulatory investment tax credits of approximately $28.0 million and $20.7 million at December 31, 2017 and 2016, 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 2018 and 2045. 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 are refundable. 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, 2016, to December 31, 2017, to deferred income tax benefit:

	2017
	(In thousands)
Change in net deferred income tax liability from the preceding table	$ (320,955)
Deferred taxes associated with other comprehensive loss	1,182
Deferred taxes associated with TCJA enactment for regulated activities	285,520
Other	8,830
Deferred income tax benefit for the period	$ (25,423)

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,	2017		2016		2015	
	Amount	**%**	Amount	%	Amount	%
			(Dollars in thousands)			
Computed tax at federal statutory rate	**$ 122,509**	**35.0**	$ 114,179	35.0	$ 86,468	35.0
Increases (reductions) resulting from:						
State income taxes, net of federal income tax	**10,724**	**3.1**	9,027	2.8	8,208	3.3
Federal renewable energy credit	**(13,958)**	**(4.0)**	(13,544)	(4.2)	(3,400)	(1.4)
Tax compliance and uncertain tax positions	**(643)**	**(.2)**	(3,028)	(.9)	(2,607)	(1.0)
Domestic production deduction	**(6,849)**	**(2.0)**	(6,251)	(1.9)	(6,842)	(2.8)
TCJA revaluation	**(47,242)**	**(13.5)**	—	—	—	—
TCJA revaluation related to accumulated other comprehensive loss balance	**7,735**	**2.2**	—	—	—	—
Other	**(7,235)**	**(2.0)**	(7,251)	(2.3)	(11,163)	(4.5)
Total income tax expense	**$ 65,041**	**18.6**	$ 93,132	28.5	$ 70,664	28.6

Included in the TCJA is the deemed repatriation transition tax which is a one-time transition tax on previously untaxed accumulated earnings and profits of certain foreign operations that is payable over 8 years. At December 31, 2017, the Company's liability for the deemed repatriation transition tax was $447,000. Historically, deferred income taxes were accrued with respect to the Company's foreign operations.

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 2014. With few exceptions, as of December 31, 2017, the Company is no longer subject to state and local income tax examinations by tax authorities for years ending prior to 2013.

The Company had no unrecognized tax benefits (excluding interest) for the years ended December 31, 2017, 2016 and 2015.

Included in income tax expense is interest on uncertain tax positions. For the years ended December 31, 2017, 2016 and 2015, the Company recognized approximately $(99,000), $(92,000) and $122,000, respectively, of interest (income) expense in income tax expense. At December 31, 2017 and 2016, the Company had accrued receivables of approximately $46,000 and $54,000, respectively, for interest.

Note 12 - Cash Flow Information

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

	2017	2016	2015
		(In thousands)	
Interest, net*	**$ 79,638**	$ 87,920	$ 88,775
Income taxes paid, net**	**$ 112,137**	$ 105,908	$ 61,405

* Capitalized interest and AFUDC - borrowed was $966,000, $914,000 and $9.3 million for the years ended December 31, 2017, 2016 and 2015, respectively.

** Income taxes paid, net of discontinued operations, were $9.7 million, $1.3 million and $2.4 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Noncash investing transactions at December 31 were as follows:

	2017	2016	2015
		(In thousands)	
Property, plant and equipment additions in accounts payable	**$ 29,263**	$ 22,712	$ 39,754

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 and gathering services through regulated and nonregulated pipeline systems primarily in the Rocky Mountain and northern Great Plains regions of the United States. This segment also provides cathodic protection and other energy-related services. For information on the Company's natural gas and oil gathering and processing facility sold on January 1, 2017, see Note 2.

The construction materials and contracting segment operations mine, process and sell construction aggregates (crushed stone, sand and gravel); produce and sell asphalt mix; and supply ready-mixed concrete. This segment focuses on vertical integration of construction services to support the aggregate based product lines including aggregate placement, asphalt and concrete paving, and site development and grading. 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.This segment operates in the central, southern and western United States and Alaska and Hawaii.

The construction services segment provides inside and outside specialty contracting services. Its outside services include design, construction and maintenance of overhead and underground electrical distribution and transmission lines, substations, external lighting, traffic signalization, and gas pipelines, as well as utility excavation and the manufacture and distribution of transmission line construction equipment. Its inside services include design, construction and maintenance of electrical and communication wiring and infrastructure, fire suppression systems, and mechanical piping and services. This business also designs, constructs and maintains renewable energy projects. These specialty contracting services are provided to utilities and large manufacturing, commercial, industrial, institutional and government customers.

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 self-insured layers of the insured companies' general liability, automobile liability, pollution liability and other 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 Brazil.

Discontinued operations includes the results and supporting activities 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 substantially 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 Note 2.

The information below follows the same accounting policies as described in Note 1. Information on the Company's segments as of December 31 and for the years then ended was as follows:

	2017	2016	2015
		(In thousands)	
External operating revenues:			
Regulated operations:			
Electric	$ 342,805	$ 322,356	$ 280,615
Natural gas distribution	848,388	766,115	817,419
Pipeline and midstream	53,566	52,983	51,004
	1,244,759	1,141,454	1,149,038
Nonregulated operations:			
Pipeline and midstream	19,602	39,602	54,281
Construction materials and contracting	1,811,964	1,873,696	1,901,530
Construction services	1,366,317	1,072,663	907,767
Other	709	1,413	1,436
	3,198,592	2,987,374	2,865,014
Total external operating revenues	$ 4,443,351	$ 4,128,828	$ 4,014,052
Intersegment operating revenues:			
Regulated operations:			
Electric	$ —	$ —	$ —
Natural gas distribution	—	—	—
Pipeline and midstream	48,867	48,794	49,065
	48,867	48,794	49,065
Nonregulated operations:			
Pipeline and midstream	178	223	554
Construction materials and contracting	565	574	2,752
Construction services	1,285	609	18,660
Other	7,165	7,230	7,755
	9,193	8,636	29,721
Intersegment eliminations	(58,060)	(57,430)	(78,786)
Total intersegment operating revenues	$ —	$ —	$ —
Depreciation, depletion and amortization:			
Electric	$ 47,715	$ 50,220	$ 37,583
Natural gas distribution	69,381	65,426	64,756
Pipeline and midstream	16,788	24,885	27,981
Construction materials and contracting	55,862	58,413	65,937
Construction services	15,739	15,307	13,420
Other	2,001	2,067	2,070
Total depreciation, depletion and amortization	$ 207,486	$ 216,318	$ 211,747
Interest expense:			
Electric	$ 25,377	$ 24,982	$ 17,421
Natural gas distribution	31,234	30,405	29,471
Pipeline and midstream	4,990	7,903	9,895
Construction materials and contracting	14,778	15,265	15,183
Construction services	3,742	4,059	3,959
Other	3,564	5,854	15,853
Intersegment eliminations	(897)	(620)	(603)
Total interest expense	$ 82,788	$ 87,848	$ 91,179

	2017	2016	2015
		(In thousands)	
Income taxes:			
Electric	**$ 7,699**	$ 1,449	$ 11,523
Natural gas distribution	**22,756**	9,181	11,377
Pipeline and midstream	**12,281**	12,408	7,505
Construction materials and contracting	**5,405**	60,625	41,619
Construction services	**25,558**	17,748	16,432
Other	**(1,809)**	(2,028)	(9,834)
Intersegment eliminations	**(6,849)**	(6,251)	(7,958)
Total income taxes	**$ 65,041**	$ 93,132	$ 70,664
Earnings (loss) on common stock:			
Regulated operations:			
Electric	**$ 49,366**	$ 42,222	$ 35,914
Natural gas distribution	**32,225**	27,102	23,607
Pipeline and midstream	**20,620**	22,060	20,680
	102,211	91,384	80,201
Nonregulated operations:			
Pipeline and midstream	**(127)**	1,375	(7,430)
Construction materials and contracting	**123,398**	102,687	89,096
Construction services	**53,306**	33,945	23,762
Other	**(1,422)**	(3,231)	(14,941)
	175,155	134,776	90,487
Intersegment eliminations (a)	**6,849**	6,251	5,016
Earnings on common stock before loss from discontinued operations	**284,215**	232,411	175,704
Loss from discontinued operations, net of tax (a)	**(3,783)**	(300,354)	(834,080)
Loss from discontinued operations attributable to noncontrolling interest	**—**	(131,691)	(35,256)
Total earnings (loss) on common stock	**$ 280,432**	$ 63,748	$ (623,120)
Capital expenditures:			
Electric	**$ 109,107**	$ 111,134	$ 332,876
Natural gas distribution	**146,981**	126,272	130,793
Pipeline and midstream	**31,054**	34,467	18,315
Construction materials and contracting	**44,302**	37,845	48,126
Construction services	**18,630**	60,344	38,269
Other	**1,850**	2,358	3,755
Total capital expenditures (b)	**$ 351,924**	$ 372,420	$ 572,134
Assets:			
Electric (c)	**$ 1,470,922**	$ 1,406,694	$ 1,325,858
Natural gas distribution (c)	**2,201,081**	2,099,296	2,038,433
Pipeline and midstream	**566,295**	550,615	591,651
Construction materials and contracting	**1,238,696**	1,220,459	1,261,963
Construction services	**591,382**	513,093	442,845
Other (d)	**261,419**	283,255	287,940
Assets held for sale	**4,871**	211,055	616,464
Total assets	**$ 6,334,666**	$ 6,284,467	$ 6,565,154

	2017	2016	2015
		(In thousands)	
Property, plant and equipment:			
Electric (c)	$ 1,982,264	$ 1,888,613	$ 1,786,148
Natural gas distribution (c)	2,319,845	2,179,413	2,076,581
Pipeline and midstream	700,284	672,199	758,729
Construction materials and contracting	1,560,048	1,549,375	1,553,428
Construction services	177,265	171,361	163,279
Other	31,123	49,268	49,537
Less accumulated depreciation, depletion and amortization	2,691,641	2,578,902	2,489,322
Net property, plant and equipment	$ 4,079,188	$ 3,931,327	$ 3,898,380

(a) Includes eliminations for the presentation of income tax adjustments between continuing and discontinued operations.
(b) Capital expenditures for 2017, 2016 and 2015 include noncash capital expenditure-related accounts payable and AFUDC, totaling $10.5 million, $(15.8) million and $35.3 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 qualified 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, 2017 and 2016, and amounts recognized in the Consolidated Balance Sheets at December 31, 2017 and 2016, were as follows:

	Pension Benefits		Other Postretirement Benefits	
	2017	2016	**2017**	2016
	(In thousands)			
Change in benefit obligation:				
Benefit obligation at beginning of year	**$ 436,307**	$ 442,960	**$ 89,304**	$ 92,734
Service cost	**—**	—	**1,508**	1,647
Interest cost	**16,207**	17,218	**3,265**	3,688
Plan participants' contributions	**—**	—	**1,368**	1,405
Actuarial (gain) loss	**19,119**	1,882	**1,781**	(3,872)
Benefits paid	**(25,710)**	(25,753)	**(6,020)**	(6,298)
Benefit obligation at end of year	**445,923**	436,307	**91,206**	89,304
Change in net plan assets:				
Fair value of plan assets at beginning of year	**333,509**	332,667	**82,846**	82,593
Actual gain on plan assets	**45,473**	26,595	**9,612**	4,184
Employer contribution	**1,112**	—	**933**	962
Plan participants' contributions	**—**	—	**1,368**	1,405
Benefits paid	**(25,710)**	(25,753)	**(6,020)**	(6,298)
Fair value of net plan assets at end of year	**354,384**	333,509	**88,739**	82,846
Funded status - under	**$ (91,539)**	$ (102,798)	**$ (2,467)**	$ (6,458)
Amounts recognized in the Consolidated Balance Sheets at December 31:				
Deferred charges and other assets - other	**$ —**	$ —	**$ 19,114**	$ 13,131
Other accrued liabilities	**—**	—	**612**	538
Deferred credits and other liabilities - other	**91,539**	102,798	**20,969**	19,051
Benefit obligation liabilities - net amount recognized	**$ (91,539)**	$ (102,798)	**$ (2,467)**	$ (6,458)
Amounts recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities) consist of:				
Actuarial loss	**$ 186,486**	$ 198,668	**$ 13,423**	$ 17,470
Prior service credit	**—**	—	**(11,632)**	(13,003)
Total	**$ 186,486**	$ 198,668	**$ 1,791**	$ 4,467

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:

	2017	2016
	(In thousands)	
Projected benefit obligation	**$ 445,923**	$ 436,307
Accumulated benefit obligation	**$ 445,923**	$ 436,307
Fair value of plan assets	**$ 354,384**	$ 333,509

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		
	2017	2016	2015	**2017**	2016	2015
	(In thousands)					
Components of net periodic benefit cost (credit):						
Service cost	**$ —**	$ —	$ 86	**$ 1,508**	$ 1,647	$ 1,816
Interest cost	**16,207**	17,218	17,141	**3,265**	3,688	3,607
Expected return on assets	**(20,528)**	(20,924)	(22,254)	**(4,641)**	(4,533)	(4,795)
Amortization of prior service cost (credit)	**—**	—	36	**(1,371)**	(1,371)	(1,371)
Recognized net actuarial loss	**6,355**	6,215	7,016	**857**	1,491	1,960
Curtailment loss	**—**	—	258	**—**	—	—
Net periodic benefit cost (credit), including amount capitalized	**2,034**	2,509	2,283	**(382)**	922	1,217
Less amount capitalized	**310**	381	316	**(370)**	(52)	120
Net periodic benefit cost (credit)	**1,724**	2,128	1,967	**(12)**	974	1,097
Other changes in plan assets and benefit obligations recognized in accumulated comprehensive (income) loss or regulatory assets (liabilities):						
Net (gain) loss	**(5,827)**	(3,789)	8,257	**(3,190)**	(3,523)	(1,336)
Amortization of actuarial loss	**(6,355)**	(6,215)	(7,016)	**(857)**	(1,491)	(1,960)
Amortization of prior service (cost) credit	**—**	—	(294)	**1,371**	1,371	1,371
Total recognized in accumulated other comprehensive (income) loss or regulatory assets (liabilities)	**(12,182)**	(10,004)	947	**(2,676)**	(3,643)	(1,925)
Total recognized in net periodic benefit cost (credit), accumulated other comprehensive (income) loss and regulatory assets (liabilities)	**$ (10,458)**	$ (7,876)	$ 2,914	**$ (2,688)**	$ (2,669)	$ (828)

The estimated net loss for the defined benefit pension plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2018 is $7.0 million. The estimated net loss and prior service credit for the other postretirement benefit plans that will be amortized from accumulated other comprehensive loss and regulatory assets into net periodic benefit cost in 2018 are $800,000 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	
	2017	2016	**2017**	2016
Discount rate	**3.38%**	3.83%	**3.41%**	3.86%
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	
	2017	2016	**2017**	2016
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%

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, 2017, 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 20 percent to 25 percent equity securities and 75 percent to 80 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:

	2017	2016
Health care trend rate assumed for next year	**7.5% – 8.5%**	8.6% – 10.7%
Health care cost trend rate - ultimate	**4.5%**	4.5%
Year in which ultimate trend rate achieved	**2024**	2024

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, 2017:

	1 Percentage Point Increase	1 Percentage Point Decrease
	(In thousands)	
Effect on total of service and interest cost components	$ 306	$ (247)
Effect on postretirement benefit obligation	$ 5,433	$ (4,551)

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, 2017 and 2016, 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, 2017, 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, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 3,814	$ —	$ 3,814
Equity securities:				
U.S. companies	13,345	—	—	13,345
International companies	1,766	—	—	1,766
Collective and mutual funds*	171,822	67,749	—	239,571
Corporate bonds	—	74,956	—	74,956
Municipal bonds	—	16,839	—	16,839
U.S. Government securities	1,038	—	—	1,038
Total assets measured at fair value	$ 187,971	$ 163,358	$ —	$ 351,329

* Collective and mutual funds invest approximately 31 percent in common stock of international companies, 28 percent in corporate bonds, 19 percent in common stock of large-cap U.S. companies, 7 percent in cash equivalents, 1 percent in U.S. Government securities and 14 percent in other investments.

	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.

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, 2017 and 2016, 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, 2017, 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, 2017
	(In thousands)			
Assets:				
Cash equivalents	$ —	$ 4,815	$ —	$ 4,815
Equity securities:				
U.S. companies	2,316	—	—	2,316
International companies	4	—	—	4
Insurance contract*	3	81,601	—	81,604
Total assets measured at fair value	$ 2,323	$ 86,416	$ —	$ 88,739

* The insurance contract invests approximately 38 percent in corporate bonds, 23 percent in common stock of large-cap U.S. companies, 21 percent in U.S. Government securities, 9 percent in mortgage-backed securities and 9 percent in other investments.

	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.

The Company expects to contribute approximately $17.7 million to its defined benefit pension plans and approximately $800,000 to its postretirement benefit plans in 2018.

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)	
2018	$ 25,111	$ 5,490	$ 152
2019	25,280	5,525	147
2020	25,587	5,396	141
2021	25,866	5,391	132
2022	26,185	5,470	123
2023 - 2027	130,994	27,106	454

Nonqualified benefit plans

In addition to the qualified defined pension benefit plans 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 $4.7 million, $1.8 million and $7.1 million in 2017, 2016 and 2015, 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 $102.5 million and $101.8 million at December 31, 2017 and 2016, respectively. The accumulated benefit obligation for these plans was $102.5 million and $101.8 million at December 31, 2017 and 2016, respectively. A weighted average discount rate of 3.20 percent and 3.56 percent at December 31, 2017 and 2016, respectively, was used to determine the benefit obligation. No rate of compensation increase was used to determine the benefit obligation at December 31, 2017 and 2016, due to the plans being froze. A discount rate of 3.56 percent and 3.77 percent for the years ended December 31, 2017 and 2016, respectively, and a rate of compensation increase of 4.00 percent for the year ended 2016 was used to determine net periodic benefit cost.

The amount of benefit payments for the unfunded, nonqualified benefit plans are expected to aggregate $7.1 million in 2018; $7.3 million in 2019; $7.7 million in 2020; $7.7 million in 2021; $7.0 million in 2022 and $37.0 million for the years 2023 through 2027.

In 2012, the Company established a nonqualified defined contribution plan for certain key management employees. Expenses incurred under this plan for 2017, 2016 and 2015 were $736,000, $395,000 and $207,000, respectively.

The Company had investments of $122.9 million and $111.0 million at December 31, 2017 and 2016, respectively, consisting of equity securities of $68.3 million and $62.5 million, respectively, life insurance carried on plan participants (payable upon the employee's death) of $36.5 million and $35.5 million, respectively, and other investments of $18.1 million and $13.0 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 $41.2 million in 2017, $40.9 million in 2016 and $36.8 million in 2015.

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 2017 and 2016 is for the plan's year-end at December 31, 2016, and December 31, 2015, 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 2017	2016	FIP/RP Status Pending/Implemented	Contributions 2017	2016	2015	Surcharge Imposed	Expiration Date of Collective Bargaining Agreement
					(In thousands)				
Alaska Laborers-Employers Retirement Fund	91-6028298-001	Yellow as of 6/30/2017	Yellow as of 6/30/2016	Implemented	**$ 690**	$ 766	$ 917	No	12/31/2018
Edison Pension Plan	93-6061681-001	Green	Green	No	**12,725**	6,242	5,517	No	6/30/2019
IBEW Local No. 82 Pension Plan	31-6127268-001	Green as of 6/30/2017	Green as of 6/30/2016	No	**1,757**	2,560	2,252	No	12/1/2019
IBEW Local 212 Pension Trust Fund	31-6127280-001	Green as of 4/30/2016	Yellow as of 4/30/2015	No	**1,312**	1,146	937	No	6/2/2019
IBEW Local No. 357 Pension Plan A	88-6023284-001	Green	Green	No	**3,286**	3,016	1,896	No	5/31/2018
IBEW Local 648 Pension Plan	31-6134845-001	Red as of 2/28/2017	Red as of 2/29/2016	Implemented	**2,254**	773	745	No	9/2/2018
Idaho Plumbers and Pipefitters Pension Plan	82-6010346-001	Green as of 5/31/2017	Green as of 5/31/2016	No	**1,156**	1,221	1,169	No	9/30/2019
Minnesota Teamsters Construction Division Pension Fund	41-6187751-001	Green as of 11/30/2016	Green as of 11/30/2015	No	**826**	690	737	No	4/30/2019
National Automatic Sprinkler Industry Pension Fund	52-6054620-001	Red	Red	Implemented	**718**	775	677	No	7/31/2018-3/31/2021
National Electrical Benefit Fund	53-0181657-001	Green	Green	No	**8,891**	6,366	5,271	No	10/31/2017-3/31/2021
Sheet Metal Workers' Pension Plan of Southern CA, AZ and NV	95-6052257-001	Yellow	Red	Implemented	**1,016**	1,087	714	No	6/30/2018
Southwest Marine Pension Trust	95-6123404-001	Red	Red	Implemented	**48**	50	26	No	1/31/2019
Other funds					**22,066**	19,835	18,254		
Total contributions					**$ 56,745**	$ 44,527	$ 39,112		

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	2016 and 2015
IBEW Local 82 Pension Plan	2016 and 2015
IBEW Local 124 Pension Trust Fund	2016 and 2015
IBEW Local 212 Pension Trust Fund	2016 and 2015
IBEW Local 357 Pension Plan A	2016 and 2015
IBEW Local 648 Pension Plan	2016 and 2015
Idaho Plumbers and Pipefitters Pension Plan	2016 and 2015
International Union of Operating Engineers Local 701 Pension Trust Fund	2016 and 2015
Minnesota Teamsters Construction Division Pension Fund	2016 and 2015
Pension and Retirement Plan of Plumbers and Pipefitters Local 525	2016 and 2015

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 in the fourth quarter of 2016.

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 $51.7 million, $36.1 million and $31.4 million for the years ended December 31, 2017, 2016 and 2015, respectively.

Amounts contributed in 2017, 2016 and 2015 to defined contribution multiemployer plans were $32.2 million, $23.8 million and $19.5 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:

	2017	2016
	(In thousands)	
Big Stone Station:		
Utility plant in service	**$ 158,084**	$ 157,144
Less accumulated depreciation	**51,740**	49,568
	$ 106,344	$ 107,576
Coyote Station:		
Utility plant in service	**$ 155,287**	$ 156,334
Less accumulated depreciation	**103,897**	105,928
	$ 51,390	$ 50,406
Wygen III:		
Utility plant in service	**$ 65,065**	$ 66,251
Less accumulated depreciation	**7,652**	7,550
	$ 57,413	$ 58,701

Note 16 - Regulatory Matters

The Company regularly reviews the need for electric and natural gas rate changes in each of the jurisdictions in which service is provided. The Company files for rate adjustments to seek recovery of operating costs and capital investments, as well as reasonable returns as allowed by regulators. The Company's most recent cases by jurisdiction are discussed in the following paragraphs. The jurisdictions in which the Company provides service have requested the Company furnish plans for the effect of the reduced corporate tax rate due to the enactment of the TCJA which may impact the Company's rates. The following paragraphs include additional details on each jurisdiction's request.

IPUC

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 January 17, 2017, Intermountain provided the IPUC with an updated revenue request of approximately $9.4 million. On April 28, 2017, the IPUC issued an order approving an increase of approximately $4.1 million or approximately 1.6 percent above current rates based on a 9.5 percent return on equity effective with service rendered on and after May 1, 2017. On May 18, 2017, Intermountain filed a petition for reconsideration with the IPUC requesting the reconsideration of certain items denied in the order dated April 28, 2017. On June 15, 2017, the IPUC granted the request for reconsideration. On August 17, 2017, Intermountain, the IPUC staff and the interveners of the case filed a stipulation and settlement resolving all issues. The stipulation and settlement reflected an increase of approximately $1.2 million or 1.36 percent more in annual revenue than the amounts approved on April 28, 2017, as well as changes in billing determinants. The total annual increase in revenue of approximately $6.7 million was approved by the IPUC on September 14, 2017, with rates effective October 1, 2017.

On January 17, 2018, the IPUC issued a general order initiating the investigation of the impacts of the TCJA. The order required the tax rate reduction to be deferred as a regulatory liability and for companies to report on the expected impacts of the TCJA by March 30, 2018.

MNPUC

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. 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. On October 6, 2017, the MNPUC approved the implementation of the natural gas utility infrastructure cost tariff to collect an annual increase of approximately $456,000. Great Plains submitted a compliance filing on October 10, 2017, and the rates were implemented for service rendered on and after November 1, 2017.

On December 29, 2017, the MNPUC issued a notice of investigation related to tax changes with the enactment of the TCJA. On January 19, 2018, the MNPUC issued a notice of request for information, commission planning meeting and subsequent comment period. Great Plains was to provide preliminary impacts of the TCJA by January 30, 2018. A commission planning meeting was held on February 6, 2018, to discuss the impacts of the TCJA. Initial filings addressing the impacts of the TCJA are to be submitted by March 2, 2018.

MTPSC

On September 25, 2017, Montana-Dakota filed an application with the MTPSC for a natural gas rate increase of approximately $2.8 million annually or approximately 4.1 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota is also introducing an SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately $1.6 million or approximately 2.3 percent, subject to refund. On December 27, 2017, the MTPSC requested Montana-Dakota identify a plan for the impacts of the TCJA for the natural gas segment within the natural gas rate case. On January 12, 2018, Montana-Dakota filed a revised interim increase of approximately $764,000, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate. A hearing is scheduled for April 26, 2018. This matter is pending before the MTPSC.

On December 27, 2017, the MTPSC requested Montana-Dakota identify a plan for the impacts of the TCJA and to file a proposal for the impacts on the electric segment by March 31, 2018.

NDPSC

On June 30, 2017, Montana-Dakota filed an application for advance determination of prudence and a certificate of public convenience and necessity with the NDPSC to purchase an expansion of the Thunder Spirit Wind farm. The advance determination of prudence would provide Montana-Dakota with assurance that the project is prudent and in the best interest of the public and assists in the recovery of Montana-Dakota's investment upon completion of the project. The expansion is expected to serve customers by the end of 2018 and is estimated to cost approximately $85 million. On November 16, 2017, the NDPSC granted Montana-Dakota's request for an advance determination of prudence and certificate of public convenience and necessity to acquire and operate the Thunder Spirit Wind farm expansion.

On July 21, 2017, Montana-Dakota filed an application with the NDPSC for a natural gas rate increase of approximately $5.9 million annually or approximately 5.4 percent above current rates. The requested increase is primarily to recover the increased investment in distribution facilities to enhance system safety and reliability and the depreciation and taxes associated with the increase in investment. Montana-Dakota is also introducing an SSIP and the proposed adjustment mechanism required to fund the SSIP. Montana-Dakota requested an interim increase of approximately $4.6 million or approximately 4.2 percent, subject to refund. On September 6, 2017, the NDPSC approved the request for interim rates effective with service rendered on or after September 19, 2017. On January 12, 2018, Montana-Dakota requested a delay of the rate case as a result of the enactment of the TCJA to allow the Company time to investigate the implications of the TCJA on the rate case. On February 14, 2018, the NDPSC approved the delay of hearing and scheduled it to begin on May 30, 2018. Also on February 14, 2018, Montana-Dakota filed a revised interim increase request of approximately $2.7 million, subject to refund, incorporating the estimated impacts of the TCJA reduction in the federal corporate income tax rate.This matter is pending before the NDPSC.

On January 10, 2018, the NDPSC issued a general order initiating the investigation into the effects of the TCJA. The order required regulatory deferral accounting on the impacts of the TCJA and for companies to file comments and the expected impacts. On February 15, 2018, Montana-Dakota filed a summary of the primary impacts of the TCJA on the electric and natural gas utilities.

OPUC

On September 29, 2017, Cascade filed an application with the OPUC for an annual pipeline replacement safety cost recovery mechanism of approximately $784,000 or approximately 1.2 percent of additional revenue. The requested increase includes incremental pipeline replacement investments associated with qualifying pipeline integrity projects. This matter is pending before the OPUC.

On December 29, 2017, Cascade filed a request with the OPUC to use deferral accounting for the 2018 net benefits associated with the implementation of the TCJA.

SDPUC

On December 29, 2017, the SDPUC issued an order initiating the investigation into the effects of the TCJA. The order required Montana-Dakota to provide comments by February 1, 2018, regarding the general effects of the TCJA on the cost of service in South Dakota and possible mechanisms for adjusting rates. The order also stated that all rates impacted by the federal income tax shall be adjusted effective January 1, 2018, subject to refund.

WUTC

On May 31, 2017, Cascade filed an application with the WUTC for an annual pipeline replacement cost recovery mechanism of approximately $1.6 million or approximately .75 percent of additional revenue. The requested increase includes incremental pipeline replacement investments associated with qualifying pipeline integrity projects. On October 12, 2017, Cascade filed a required update revising the request to approximately $1.3 million or approximately .61 percent of additional revenue and on October 26, 2017, the WUTC approved the order with rates effective November 1, 2017.

On August 31, 2017, Cascade filed an application with the WUTC for a natural gas rate increase of approximately $5.9 million annually or approximately 2.7 percent above current rates. The requested increase includes costs associated with increased infrastructure investment and the associated operating expenses. Also included in the request is recovery of operation and maintenance costs associated with a maximum allowable operating pressure validation plan. On January 3, 2018, the WUTC filed a bench request requiring Cascade to provide information related to the impacts of the TCJA on Cascade's revenue requirement and a proposed ratemaking treatment of those impacts. On January 12, 2018, Cascade filed a response to the bench request reducing the revenue requirement to approximately $1.7 million annually, which includes the estimated impacts of the TCJA. This matter is pending before the WUTC.

WYPSC

On December 29, 2017, the WYPSC issued a general order requiring regulatory deferral accounting on the impacts of the TCJA. A technical conference was held on February 6, 2018, to discuss the implications of the TCJA.

FERC

On September 1, 2017, Montana-Dakota submitted an update to its transmission formula rate under the MISO tariff, which reflects an incremental increase of approximately $2.5 million to include a revenue requirement for the Company's multivalue project, for a total of $13.6 million, which was effective January 1, 2018.

Montana-Dakota and certain MISO Transmission Owners with projected rates submitted a filing to the FERC on February 1, 2018, requesting the FERC to waive certain provisions of the MISO tariff in order for Montana-Dakota and certain MISO Transmission Owners with projected rates to revise their rates to reflect the reduction in the corporate tax rate. Under the MISO tariff, rates are to be changed only on an annual basis with any changes reflected in subsequent true-ups. If the waiver is granted, MISO expects to implement new rates reflecting the reduction in the tax rate beginning with services rendered on March 1, 2018, and will re-bill January and February 2018 services to reflect the new rates.

On February 7, 2018, WBI Energy Transmission announced it will hold an initial rate change pre-filing settlement meeting with customers on April 10, 2018. In accordance with WBI Energy Transmission’s offer of settlement and stipulation and agreement with the FERC dated June 4, 2014, the Company is to make a filing with new proposed rates to be effective no later than May 1, 2019. Assuming a five-month suspension period, WBI Energy Transmission would expect to file by October 31, 2018.

Note 17 - Commitments and Contingencies

The Company is party to claims and lawsuits arising out of its business and that of its consolidated subsidiaries, which may include, but are not limited to, matters involving property damage, personal injury, and environmental, contractual, statutory and regulatory obligations. 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. Accruals are based on the best information available, but in certain situations management is unable to estimate an amount or range of a reasonably possible loss including, but not limited to when: (1) the damages are unsubstantiated or indeterminate, (2) the proceedings are in the early stages, (3) numerous parties are involved, or (4) the matter involves novel or unsettled legal theories. The Company accrued liabilities of $35.4 million and $31.8 million, which have not been discounted, including liabilities held for sale, for contingencies, including litigation, production taxes, royalty claims and environmental matters at December 31, 2017 and 2016, respectively. This includes amounts that may have been accrued for matters discussed in Litigation and Environmental matters within this note. The Company will continue to monitor each matter and adjust accruals as might be warranted based on new information and further developments. Management believes that the outcomes with respect to probable and reasonably possible losses in excess of the amounts accrued, net of insurance recoveries, while uncertain, either cannot be estimated or will not have a material effect upon the Company's financial position, results of operations or cash flows. Unless otherwise required by GAAP, legal costs are expensed as they are incurred.

Litigation

Construction Services Capital Electric provided employees in 2012 to perform work for a contractor on a project in Kansas. One of the Capital Electric employees was injured while working on the project and brought a lawsuit against the contractor. Judgment was entered in favor of the employee and his spouse on November 3, 2016, in the amount of $44.8 million following a court determination that the employee's injuries were caused by the contractor's negligence. The contractor claims that Capital Electric was contractually required, but failed, to name the contractor as an additional insured under any liability policy in effect at the time of the project and that such failure resulted in the entry of judgment against the contractor. In March 2017, Capital Electric filed a petition for declaratory judgment in the District Court of Wyandotte County, Kansas for a judicial determination that any agreement between Capital Electric and the contractor for the project did not require Capital Electric to include the contractor as an additional insured under any liability policy issued to Capital Electric and that if such an agreement was found to exist, it would be void and unenforceable under Kansas law. Subsequent to December 31, 2017, the matter has been settled with Capital Electric being released from all claims of liability and the declaratory judgment action being dismissed.

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 an 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. The Oregon DEQ released an ROD in January 2015 that selected a remediation alternative for the site as recommended in an earlier staff report. The total estimated cost for the selected remediation, including long-term maintenance, is approximately $3.5 million of which $400,000 has been incurred. It is not known at this time what share of the cleanup costs will actually be borne by Cascade; however, Cascade has paid 50 percent of the ongoing investigation and design costs and anticipates its proportional share of the final costs could be approximately 50 percent. Cascade has an accrual balance of $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, December 1, 2015, December 1, 2016 and December 1, 2017.

The second claim is for contamination at the Bremerton Gasworks Superfund 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. Current estimates for the cost to complete the remedial investigation and feasibility study are approximately $7.6 million of which $1.7 million has been incurred. Cascade has accrued $5.9 million for the remedial investigation and feasibility study as well as $6.4 million for remediation of this site; however, the accrual for remediation costs will be reviewed and adjusted, if necessary, after completion of the remedial investigation and feasibility study. 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 not recorded an accrual for this site.

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 intends to 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, 2017, were:

	2018	2019	2020	2021	2022	Thereafter
			(In thousands)			
Operating leases	$ 55,511	$ 45,307	$ 33,168	$ 18,562	$ 7,047	$ 40,833

Rent expense was $73.7 million, $65.0 million and $53.9 million for the years ended December 31, 2017, 2016 and 2015, 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. The commitment terms vary in length, up to 43 years. The commitments under these contracts as of December 31, 2017, were:

	2018	2019	2020	2021	2022	Thereafter
			(In thousands)			
Purchase commitments	$ 360,751	$ 215,005	$ 162,424	$ 135,334	$ 99,068	$ 773,820

These commitments were not reflected in the Company's consolidated financial statements. Amounts purchased under various commitments for the years ended December 31, 2017, 2016 and 2015, were $516.1 million, $539.3 million and $842.1 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 $56.3 million at December 31, 2017, and are expected to mature in 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 sale 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, 2017, the fixed maximum amounts guaranteed under these agreements aggregated $108.0 million. The amounts of scheduled expiration of the maximum amounts guaranteed under these agreements aggregate $6.4 million in 2018; $25.9 million in 2019; $68.7 million in 2020; $500,000 in 2021; $500,000 in 2022; $2.0 million thereafter; and $4.0 million, which has no scheduled maturity date. There were no amounts outstanding under the above guarantees at December 31, 2017. 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, 2017, the fixed maximum amounts guaranteed under these letters of credit aggregated $34.0 million, all of which expire in 2018. There were no amounts outstanding under the above letters of credit at December 31, 2017. 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, 2017.

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, 2017, approximately $616.5 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.

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 electric 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, 2017, 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 $40.8 million.

Supplementary Financial Information

Quarterly Data (Unaudited)

The following unaudited information shows selected items by quarter for the years 2017 and 2016:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(In thousands, except per share amounts)			
2017				
Operating revenues	**$ 937,925**	**$ 1,067,639**	**$ 1,272,548**	**$ 1,165,239**
Operating expenses	**870,813**	**987,960**	**1,116,171**	**1,039,695**
Operating income	**67,112**	**79,679**	**156,377**	**125,544**
Income from continuing operations	**35,638**	**44,405**	**89,549**	**115,394**
Income (loss) from discontinued operations attributable to the Company, net of tax	**1,687**	**(3,190)**	**(2,198)**	**(82)**
Net income attributable to the Company	**37,325**	**41,215**	**87,351**	**115,312**
Earnings per common share - basic:				
Earnings before discontinued operations	**.18**	**.22**	**.46**	**.59**
Discontinued operations attributable to the Company, net of tax	**.01**	**(.01)**	**(.01)**	**—**
Earnings per common share - basic	**.19**	**.21**	**.45**	**.59**
Earnings per common share - diluted:				
Earnings before discontinued operations	**.18**	**.22**	**.46**	**.59**
Discontinued operations attributable to the Company, net of tax	**.01**	**(.01)**	**(.01)**	**—**
Earnings per common share - diluted	**.19**	**.21**	**.45**	**.59**
Weighted average common shares outstanding:				
Basic	**195,304**	**195,304**	**195,304**	**195,304**
Diluted	**196,023**	**195,973**	**195,783**	**195,617**
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

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.
- First quarter 2016 has 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.
- Fourth quarter 2017 reflects an income tax benefit of $39.5 million related to the TCJA. For more information, see Note 11.

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 substantially all of

Fidelity's oil and natural gas assets. The completion of these sales occurred between October 2015 and April 2016. Prior to the asset sales, Fidelity was significantly involved in the development and production of oil and natural gas resources. Upon the completion of the asset sales, the Company had no remaining proved oil, NGL or natural gas reserves. 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 were 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. For more information, see Note 2.

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
Andeavor Field Services LLC	Formerly QEP Field Services, LLC doing business as Tesoro Logistics Rockies LLC
ASC	FASB Accounting Standards Codification
ATBs	Atmospheric tower bottoms
Big Stone Station	475-MW coal-fired electric generating facility near Big Stone City, South Dakota (22.7 percent ownership)
Brazilian Transmission Lines	Company's former investment in companies owning three electric transmission lines in Brazil
Calumet	Calumet Specialty Products Partners, L.P.
Capital Electric	Capital Electric Construction Company, Inc., a direct wholly owned subsidiary of MDU Construction Services
Cascade	Cascade Natural Gas Corporation, an indirect wholly owned subsidiary of MDU Energy Capital
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
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.
MNPUC	Minnesota Public Utilities Commission
Montana-Dakota	Montana-Dakota Utilities Co., a public utility division of the Company
MTPSC	Montana Public Service Commission
MW	Megawatt

NDPSC	North Dakota Public Service Commission
NGL	Natural gas liquids
Oil	Includes crude oil and condensate
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's 50 percent ownership interests were sold effective January 1, 2017)
PRP	Potentially Responsible Party
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
SSIP	System Safety and Integrity Program
Stock Purchase Plan	Company's Dividend Reinvestment and Direct Stock Purchase Plan which was terminated effective December 5, 2016
TCJA	Tax Cuts and Jobs Act
Tesoro	Tesoro Refining & Marketing Company LLC
VIE	Variable interest entity
Washington DOE	Washington State Department of Ecology
WBI Energy	WBI Energy, Inc., a direct 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, 2017, 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, 2017, 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)	692,761	(2)	$ —	(3)	4,662,030	(4)(5)
Equity compensation plans not approved by stockholders	N/A		N/A		N/A	
Total	692,761		$ —		4,662,030	

(1) Consists of the Non-Employee Director Long-Term Incentive Compensation Plan and the Long-Term Performance-Based Incentive Plan.
(2) Consists of performance shares.
(3) No weighted average exercise price is shown for the performance shares.
(4) This amount includes 4,307,574 shares available for future issuance under the Long-Term Performance-Based Incentive Plan in connection with grants of restricted stock, performance units, performance shares or other equity-based awards.
(5) This amount includes 354,456 shares available for future issuance under the Non-Employee Director Long-Term Incentive Compensation Plan. Under this plan, in addition to a cash retainer, non-employee directors, excluding the Chair of the Board, are awarded shares equal in value to $110,000 annually and the Chair of the Board is awarded shares equal in value to $145,000 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 Accounting 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, 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,	2017	2016	2015
		(In thousands)	
Operating revenues	$ **623,693**	$ 561,266	$ 556,112
Operating expenses	**516,524**	469,062	478,198
Operating income	**107,169**	92,204	77,914
Other income	**1,331**	1,491	8,318
Interest expense	**31,997**	31,519	23,562
Income before income taxes	**76,503**	62,176	62,670
Income taxes	**13,800**	6,355	15,882
Equity in earnings of subsidiaries from continuing operations	**222,283**	177,275	129,601
Net income from continuing operations	**284,986**	233,096	176,389
Equity in loss of subsidiaries from discontinued operations attributable to the Company	**(3,783)**	(168,663)	(798,824)
Loss on redemption of preferred stocks	**600**	—	—
Dividends declared on preferred stocks	**171**	685	685
Earnings (loss) on common stock	$ **280,432**	$ 63,748	$ (623,120)
Comprehensive income (loss)	$ **279,602**	$ 65,848	$ (617,480)

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,		2017		2016
	(In thousands, except shares and per share amounts)			
Assets				
Current assets:				
Cash and cash equivalents	$	**843**	$	4,159
Receivables, net		**83,453**		80,467
Accounts receivable from subsidiaries		**34,029**		34,424
Inventories		**13,864**		17,352
Prepayments and other current assets		**34,400**		24,531
Total current assets		**166,589**		160,933
Investments		**76,779**		70,370
Investment in subsidiaries		**1,704,908**		1,603,874
Property, plant and equipment		**2,631,161**		2,502,264
Less accumulated depreciation, depletion and amortization		**797,130**		756,191
Net property, plant and equipment		**1,834,031**		1,746,073
Deferred charges and other assets:				
Goodwill		**4,812**		4,812
Other		**175,599**		183,654
Total deferred charges and other assets		**180,411**		188,466
Total assets	$	**3,962,718**	$	3,769,716
Liabilities and Stockholders' Equity				
Current liabilities:				
Long-term debt due within one year	$	**100,011**	$	110
Accounts payable		**47,000**		37,697
Accounts payable to subsidiaries		**7,234**		5,592
Taxes payable		**13,717**		14,992
Dividends payable		**38,573**		37,767
Accrued compensation		**20,017**		16,086
Other accrued liabilities		**36,881**		34,929
Total current liabilities		**263,433**		147,173
Long-term debt		**612,493**		679,667
Deferred credits and other liabilities:				
Deferred income taxes		**147,847**		270,126
Other		**509,902**		356,506
Total deferred credits and other liabilities		**657,749**		626,632
Commitments and contingencies				
Stockholders' equity:				
Preferred stocks		**—**		15,000
Common stockholders' equity:				
Common stock				
Authorized - 500,000,000 shares, $1.00 par value				
Issued - 195,843,297 shares in 2017 and 2016		**195,843**		195,843
Other paid-in capital		**1,233,412**		1,232,478
Retained earnings		**1,040,748**		912,282
Accumulated other comprehensive loss		**(37,334)**		(35,733)
Treasury stock at cost - 538,921 shares		**(3,626)**		(3,626)
Total common stockholders' equity		**2,429,043**		2,301,244
Total stockholders' equity		**2,429,043**		2,316,244
Total liabilities and stockholders' equity	$	**3,962,718**	$	3,769,716

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,	2017	2016	2015
		(In thousands)	
Net cash provided by operating activities	$ 284,075	$ 238,125	$ 255,273
Investing activities:			
Capital expenditures	(146,370)	(159,570)	(349,985)
Net proceeds from sale or disposition of property and other	(5,665)	3,784	3,268
Investments in and advances to subsidiaries	(40,000)	(5,000)	(7,000)
Advances from subsidiaries	40,000	15,000	100,000
Investments	(468)	(129)	5
Net cash used in investing activities	(152,503)	(145,915)	(253,712)
Financing activities:			
Issuance of long-term debt	70,080	106,420	224,185
Repayment of long-term debt	(37,569)	(50,010)	(108,008)
Proceeds from issuance of common stock	—	—	21,898
Dividends paid	(150,727)	(147,156)	(142,835)
Redemption of preferred stock	(15,600)	—	—
Repurchase of common stock	(564)	—	—
Tax withholding on stock-based compensation	(508)	(226)	—
Net cash used in financing activities	(134,888)	(90,972)	(4,760)
Increase (decrease) in cash and cash equivalents	(3,316)	1,238	(3,199)
Cash and cash equivalents - beginning of year	4,159	2,921	6,120
Cash and cash equivalents - end of year	$ 843	$ 4,159	$ 2,921

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

Notes to Condensed Financial Statements

Note 1 - Summary of Significant Accounting Policies

Basis of presentation The condensed financial information reported in Schedule I is being presented to comply with Rule 12-04 of Regulation S-X. The information is unconsolidated and is presented for the parent company only, which is comprised of MDU Resources Group, Inc. (the Company) and Montana-Dakota and Great Plains, public utility divisions of the Company. In Schedule I, investments in subsidiaries are presented under the equity method of accounting where the assets and liabilities of the subsidiaries are not consolidated. The investments in net assets of the subsidiaries are recorded on the Condensed Balance Sheets. The income from subsidiaries is reported as equity in earnings of subsidiaries on the Condensed Statements of Income. The consolidated financial statements of MDU Resources Group, Inc. reflect certain businesses as discontinued operations. 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 At December 31, 2017, the Company had long-term debt maturities, excluding unamortized debt issuance costs, of $100.0 million in 2018, $74.5 million in 2019, $700,000 in 2020, $700,000 in 2021, $700,000 in 2022 and $538.1 million scheduled to mature in years after 2022.

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 $116.1 million, $115.8 million and $110.6 million for the years ended December 31, 2017, 2016 and 2015, respectively.

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

For the years ended December 31, 2017, 2016 and 2015

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:					
2017	**$ 10,479**	**$ 7,024**	**$ 989**	**$ 10,423**	**$ 8,069**
2016	9,835	8,302	851	8,509	10,479
2015	9,511	11,343	1,012	12,031	9,835

* 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.

Item 16. Form 10-K Summary

None.

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference: Form	Period Ended	Exhibit	Filing Date	File Number
2(a)	Membership Interest Purchase Agreement, dated as of June 24, 2016, between WBI Energy, Inc. and Tesoro Refining & Marketing Company LLC		8-K/A		2.1	7/21/16	1-03480
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.		8-K/A		2.2	7/21/16	1-03480
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.		8-K/A		2.3	7/21/16	1-03480
3(a)	Restated Certificate of Incorporation of MDU Resources Group, Inc., as amended, dated May 13, 2010		10-Q	9/30/10	3(a)	11/3/10	1-03480
3(b)	Bylaws of MDU Resources Group, Inc., as amended and restated on February 16, 2017		8-K		3.1	2/21/17	1-03480
4(a)	Indenture, dated as of December 15, 2003, between MDU Resources Group, Inc. and The Bank of New York, as trustee		S-8		4(f)	1/21/04	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		10-K	12/31/09	4(c)	2/17/10	1-03480
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		10-Q	6/30/05	4(a)	8/3/05	1-03480
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		10-Q	6/30/06	4(a)	8/4/06	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
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		10-K	12/31/15	4(e)	2/19/16	1-03480
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		10-K	12/31/15	4(f)	2/19/16	1-03480
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		10-K	12/31/11	4(e)	2/24/12	1-03480
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		10-Q	9/30/12	4	11/7/12	1-03480
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		10-Q	6/30/14	4(a)	8/8/14	1-03480
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		10-Q	6/30/14	4(b)	8/8/14	1-03480
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		10-Q	9/30/16	4	11/7/16	1-03480
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		8-K		4	8/16/07	1-03480
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		10-Q	9/30/08	4(b)	11/5/08	1-03480
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		8-K		4	8/12/92	1-07196
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		10-Q	6/30/93	4		1-07196
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		8-K		4.1	1/26/05	1-07196
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		8-K		4.1	3/8/07	1-07196
+10(a)	MDU Resources Group, Inc. Supplemental Income Security Plan, as amended and restated May 10, 2017		10-Q	6/30/17	10(d)	8/4/17	1-03480
+10(b)	MDU Resource Group, Inc. Director Compensation Policy, as amended May 10, 2017		10-Q	6/30/17	10(a)	8/4/17	1-03480

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
+10(c)	Deferred Compensation Plan for Directors, as amended May 15, 2008		10-Q	6/30/08	10(a)	8/7/08	1-03480
+10(d)	Non-Employee Director Stock Compensation Plan, as amended May 12, 2011		10-Q	6/30/11	10(a)	8/5/11	1-03480
+10(e)	MDU Resources Group, Inc. Non-Employee Director Long-Term Incentive Compensation Plan, as amended May 17, 2012		10-Q	6/30/12	10(a)	8/7/12	1-03480
+10(f)	MDU Resources Group, Inc. Long-Term Performance-Based Incentive Plan, as amended February 11, 2016		10-K	12/31/15	10(f)	2/19/16	1-03480
+10(g)	MDU Resources Group, Inc. Executive Incentive Compensation Plan, as amended May 10, 2017, and Rules and Regulations, as amended May 9, 2017		10-Q	6/30/17	10(b)	8/4/17	1-03480
+10(h)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 11, 2015		8-K		10.3	2/18/15	1-03480
+10(i)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016		8-K		10.3	2/18/16	1-03480
+10(j)	Form of Performance Share Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 16, 2017		8-K		10.1	2/21/17	1-03480
+10(k)	Form of Annual Incentive Award Agreement under the Long-Term Performance-Based Incentive Plan, as amended February 10, 2016		8-K		10.2	2/18/16	1-03480
+10(l)	Form of MDU Resources Group, Inc. Indemnification Agreement for Section 16 Officers and Directors, dated May 15, 2014		8-K		10.1	5/15/14	1-03480
+10(m)	Form of Amendment No. 1 to Indemnification Agreement, dated May 15, 2014		8-K		10.2	5/15/14	1-03480
+10(n)	MDU Resources Group, Inc. Section 16 Officers and Directors with Indemnification Agreements Chart, as of October 10, 2017		10-Q	9/30/17	10(b)	11/3/17	1-03480
+10(o)	MDU Resources Group, Inc. Nonqualified Defined Contribution Plan, as amended May 10, 2017		10-Q	6/30/17	10(c)	8/4/17	1-03480
+10(p)	MDU Resources Group, Inc. 401(k) Retirement Plan, as restated January 1, 2017		10-Q	3/31/17	10(a)	5/8/17	1-03480
+10(q)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated March 31, 2017		10-Q	3/31/17	10(b)	5/8/17	1-03480
+10(r)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated April 10, 2017		10-Q	6/30/17	10(e)	8/4/17	1-03480
+10(s)	Instrument of Amendment to the MDU Resources Group, Inc. 401(k) Retirement Plan, dated August 30, 2017		10-Q	9/30/17	10(a)	11/3/17	1-03480
+10(t)	Employment Letter for Jeffrey S. Thiede, dated May 16, 2013		10-K	12/31/13	10(ab)	2/21/14	1-03480
+10(u)	Martin A. Fritz Offer Letter, dated July 1, 2015		8-K		10.2	7/2/15	1-03480
+10(v)	Jason L. Vollmer Offer Letter, dated March 7, 2016		8-K		10.2	3/8/16	1-03480
+10(w)	Jason L. Vollmer Offer Letter, dated September 20, 2017		8-K		10.1	9/21/17	1-03480
12	Computation of Ratio of Earnings to Fixed Charges and Combined Fixed Charges and Preferred Stock Dividends	X					
21	Subsidiaries of MDU Resources Group, Inc.	X					
23	Consent of Independent Registered Public Accounting Firm	X					
31(a)	Certification of Chief Executive Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					

Part IV

Exhibit Number	Exhibit Description	Filed Herewith	Incorporated by Reference Form	Period Ended	Exhibit	Filing Date	File Number
31(b)	Certification of Chief Financial Officer filed pursuant to Section 302 of the Sarbanes-Oxley Act of 2002	X					
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	X					
95	Mine Safety Disclosures	X					
101.INS	XBRL Instance Document - the instance document does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document						
101.SCH	XBRL Taxonomy Extension Schema Document						
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document						
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document						
101.LAB	XBRL Taxonomy Extension Label Linkbase Document						
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document						

\+ Management contract, compensatory plan or arrangement.

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

Signatures

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

MDU Resources Group, Inc.

Date: February 23, 2018 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 23, 2018
/s/ Jason L. Vollmer Jason L. Vollmer (Vice President, Chief Financial Officer and Treasurer)	Chief Financial Officer	February 23, 2018
/s/ Stephanie A. Barth Stephanie A. Barth (Vice President, Chief Accounting Officer and Controller)	Chief Accounting Officer	February 23, 2018
/s/ Harry J. Pearce Harry J. Pearce (Chairman of the Board)	Director	February 23, 2018
/s/ Thomas Everist Thomas Everist	Director	February 23, 2018
/s/ Karen B. Fagg Karen B. Fagg	Director	February 23, 2018
/s/ Mark A. Hellerstein Mark A. Hellerstein	Director	February 23, 2018
/s/ A. Bart Holaday A. Bart Holaday	Director	February 23, 2018
/s/ Dennis W. Johnson Dennis W. Johnson	Director	February 23, 2018
/s/ William E. McCracken William E. McCracken	Director	February 23, 2018
/s/ Patricia L. Moss Patricia L. Moss	Director	February 23, 2018
/s/ John K. Wilson John K. Wilson	Director	February 23, 2018

Section 2: EX-12 (MDU RESOURCES COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES)

MDU RESOURCES GROUP, INC.
COMPUTATION OF RATIO OF EARNINGS TO FIXED CHARGES
AND COMBINED FIXED CHARGES AND PREFERRED STOCK DIVIDENDS

	Years Ended December 31,				
	2017	2016	2015	2014	2013
	(In thousands of dollars)				
Earnings Available for Fixed Charges:					
Net Income (a)	$ 284,982	$ 233,102	$ 176,545	$ 185,577	$ 171,236
Income Taxes	65,041	93,132	70,664	64,422	74,235
	350,023	326,234	247,209	249,999	245,471
Rents (b)	24,576	21,656	17,974	15,632	13,240
Interest (c)	83,091	88,045	104,292	94,613	92,255
Total Earnings Available for Fixed Charges	$ 457,690	$ 435,935	$ 369,475	$ 360,244	$ 350,966
Preferred Dividend Requirements	$ 171	$ 685	$ 685	$ 685	$ 685
Ratio of Income Before Income Taxes to Net Income	123%	140%	140%	135%	143%
Preferred Dividend Factor on Pretax Basis	210	959	959	925	980
Fixed Charges (d)	107,619	109,636	117,609	111,739	103,910
Combined Fixed Charges and Preferred Stock Dividends	$ 107,829	$ 110,595	$ 118,568	$ 112,664	$ 104,890
Ratio of Earnings to Fixed Charges	4.3x	4.0x	3.1x	3.2x	3.4x
Ratio of Earnings to Combined Fixed Charges and Preferred Stock Dividends	4.2x	3.9x	3.1x	3.2x	3.3x

(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).

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Section 3: EX-21 (MDU RESOURCES SUBSIDIARIES OF MDU RESOURCES)

MDU RESOURCES GROUP, INC.
List of Subsidiaries
(effective December 31, 2017)

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
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
Hawaiian Cement, a partnership	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
Nevada Solar Solutions, LLC	Delaware
Nevada Valley Solar Solutions I, LLC	Delaware
Northstar Materials, Inc.	Minnesota
On Electric Group, Inc.	Oregon
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
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

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Section 4: EX-23 (MDU RESOURCES CONSENT OF INDEPENDENT ACCOUNTING FIRM)

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-220026 on Form S-3, and No. 333-27877, No. 333-114488, and No. 333-212635 on Form S-8, of our reports dated February 23, 2018, 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, 2017.

/s/ Deloitte & Touche LLP

Minneapolis, Minnesota
February 23, 2018

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Section 5: EX-31.A (MDU RESOURCES CERTIFICATION OF CHIEF EXECUTIVE OFFICER)

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 23, 2018

/s/ David L. Goodin
David L. Goodin
President and Chief Executive Officer

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Section 6: EX-31.B (MDU RESOURCES CERTIFICATION OF CHIEF FINANCIAL OFFICER)

CERTIFICATION

I, Jason L. Vollmer, 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 23, 2018

/s/ Jason L. Vollmer
Jason L. Vollmer
Vice President, Chief Financial Officer and Treasurer

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Section 7: EX-32 (MDU RESOURCES CERTIFICATION OF CEO AND CFO)

**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 Jason L. Vollmer the Vice President, Chief Financial Officer and Treasurer 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, 2017 (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 23rd day of February, 2018.

/s/ David L. Goodin
David L. Goodin
President and Chief Executive Officer

/s/ Jason L. Vollmer
Jason L. Vollmer
Vice President, Chief Financial Officer and Treasurer

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.

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Section 8: EX-95 (MDU RESOURCES MINE SAFETY DISCLOSURES)

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, 2017, none of the Company's operating subsidiaries received citations or orders under the following sections of the Mine Safety Act: 104(b), 110(b)(2), 107(a) and 104(e). During the twelve months ended December 31, 2017, one of the Company's operating subsidiaries received a citation and order under Section 104(d) 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 104(d) Citations and 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 (#)
04-00081	2	—	$ 116	—	—	—
04-01698	—	—	116	—	—	—
04-05140	—	—	580	—	—	—
04-05156	—	—	116	—	—	—
04-05459	—	—	346	—	—	1
10-02088	—	—	232	—	—	—
10-02089	2	—	1,574	—	—	—
10-02170	—	—	542	—	2	2
13-02222	—	—	348	—	—	—
21-02614	1	—	668	—	—	—
21-02702	—	—	898	—	—	4
21-02718	—	—	1,331	—	—	—
21-03086	1	—	204	—	—	—
21-03096	—	—	1,216	—	—	4
21-03112	—	—	116	—	—	—
21-03127	—	—	462	—	—	—
21-03185	—	—	344	—	—	—
21-03248	3	1	2,660	1	1	—
21-03416	—	—	—	—	—	1
21-03502	1	—	685	—	—	—
21-03732	—	—	116	—	—	—
21-03783	—	—	116	—	—	1
21-03812	3	—	1,295	—	—	—
21-03870	—	—	116	—	—	—
21-03872	—	—	—	—	—	1
24-00459	—	—	232	—	—	—
24-00462	2	—	1,621	—	—	—
24-00478	—	—	116	—	—	—
24-02095	1	—	380	—	—	—
24-02414	—	—	232	—	—	—
32-00774	—	—	116	—	—	—
32-00776	1	—	668	—	—	—
32-00777	—	—	114	—	—	—
32-00950	1	—	844	—	—	—
35-00426	—	—	116	—	—	—
35-00463	—	—	232	—	—	—
35-00495	—	—	228	—	—	1
35-00512	—	—	1,273	—	—	—
35-02906	1	—	436	—	—	—
35-02968	1	—	455	—	—	—
35-03022	1	—	512	—	—	—
35-03131	—	—	580	—	—	—

MSHA Identification Number/Contractor ID	Section 104 S&S Citations (#)	Section 104(d) Citations and 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 (#)
35-03404	—	—	116	—	—	—
35-03478	—	—	116	—	—	—
35-03496	2	—	770	—	2	2
35-03505	—	—	116	—	—	—
35-03595	—	—	116	—	—	—
35-03605	—	—	230	—	—	—
35-03639	—	—	116	—	—	—
35-03667	—	—	116	—	—	—
35-03752	—	—	232	—	—	—
35-03678	—	—	129	—	—	—
41-02639	1	—	709	—	—	—
41-03931	—	—	348	—	—	—
48-01383	—	—	116	—	—	—
48-01670	—	—	361	—	—	—
50-00883	1	—	375	—	—	—
50-01196	1	—	—	—	—	—
51-00036	7	—	9,941	8	8	—
51-00171	—	—	232	—	—	—
51-00192	1	—	491	—	—	—
51-00195	—	—	232	1	1	—
51-00241	2	—	724	1	1	—
51-00242	—	—	116	—	—	—
I6K (Contractor ID)	1	—	428	—	—	—
	37	1	$ 38,482	11	15	17

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, 2017:

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
10-02170	—	2	—	—	—	—
21-03248	1	—	—	—	—	—
51-00036	8	—	—	—	—	—
51-00195	1	—	—	—	—	—
51-00241	1	—	—	—	—	—
	11	2	—	—	—	—

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